Designing Electricity Distribution Network Tariffs for Beneficial Electrification

by

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ABSTRACT

Decarbonizing the transportation and residential building sectors will require rapid electrification through the uptake of electric vehicles (EVs) and cold climate heat pumps (CCHPs), respectively. There is broad consensus that the flat volumetric electricity tariffs currently in place for residential customers in most of the US discourage electrification and do not reflect the underlying marginal costs of electricity delivery. Under flat volumetric tariffs, utilities are projecting sharp rises in distribution-level peak demand, which will necessitate network upgrades whose costs are recovered from all grid users. Alternative rate designs can help mitigate the need for these upgrades by shifting new demand away from peak periods. However, there is an emerging narrative that electricity tariff design is a zero-sum game: regulators can either protect vulnerable households or encourage electrification, but not both. In this thesis, we challenge that perception by asking whether well-designed distribution network tariffs can deliver a win-win in the long run, reducing operating costs for EVs and/or CCHPs and average network costs for households that cannot yet afford to electrify. We answer this question by running a series of bottom-up optimizations to simulate household's responses to alternative network tariff designs in two distinct geographies, then assessing cost impacts on different household groups. We use open-source data on household electricity consumption and travel behavior. We find that beyond very low adoption levels, time-of-use per-kWh network tariffs, which several states have adopted as the default, perform poorly on all metrics and lead to large increases in local peak demand. Per-kW capacity tariffs (subscription and demand charges) are effective at mitigating EV-driven peaks, especially when paired with TOU energy tariffs. We recommend that regulators separate network charges from energy charges and introduce a per-kW subscription network tariff to collect a portion of the network revenue requirement. This approach will reduce the total cost of ownership of electrified devices while mitigating the network upgrades needed to maintain reliability. Our recommendations offer a path towards rapid electrification that benefits all grid users.

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Chapter 1

Introduction: Electrification's Role in Meeting Climate Targets

Transportation and buildings are responsible for 41% of direct greenhouse gas emissions in the US [1]. To decarbonize these sectors, there is widespread consensus that electrification – replacing fossil-fueled vehicles and heating equipment with electric alternatives – offers the most cost-effective and scalable pathway [2] [3]. In transportation, where 58% emissions come from light-duty passenger vehicles [4], electrification is synonymous with the purchase of electric vehicles (EVs). For residential buildings, where space heating is the number one source of direct emissions [1], electrification requires installing cold climate heat pumps (CCHPs), which provide both heating and cooling and replace or supplement conventional boilers and furnaces fueled by natural gas, propane, or oil.

While electrification does not eliminate emissions completely, both EVs and CCHPs offer a significant reduction in emissions compared to fossil-fueled equipment [5] [6]. This emissions gap will improve as the electricity generation mix becomes cleaner, which many states have mandated through renewable portfolio standards (RPS). In addition to RPS statutes, there are numerous policy drivers for electrification. The Inflation Reduction Act, passed in 2022, provides purchase incentives for both EVs and CCHPs that reduce consumers' up-front costs. Several states offer purchase rebates that can be stacked on top of IRA funds. Furthermore, in 2020 California's governor issued an executive order (N-79-20) that all new passenger cars, trucks, and SUVs sold after 2035 must be EVs, which was codified in regulation approved by the California Air Resources Board in 2022. Nine other states, which have historically followed California's vehicle emissions standard, plan to follow suit and prohibit the sale of new internal combustion engine vehicles after 2035 [7].

Both EVs and CCHPs consume a significant amount of electricity; a typical EV uses 2,363 kWh per year for at-home charging [8]. CCHP consumption varies widely depending on climate; in cold regions, electric heating is expected to increase a home's electricity consumption by over 6,000 kWh per year [9]. Taken together, electrifying the light duty vehicle fleet and residential housing stock is projected to nearly double annual residential electricity consumption [2]. As states aim to substitute electricity as the primary "fuel" to power our vehicles and condition our buildings, the electricity grid has emerged as the backbone for decarbonization efforts.

1.1 Current Trends in US Electricity Networks

While the cost of generating electricity in the US has consistently fallen over the past 20 years, driven by cheap natural gas and the declining cost of renewables, the cost of delivering electricity has steadily grown [10]. Electricity utilities build and maintain a complex network of poles, wires, and power electronics equipment to send electricity over long distances to every building connected to the grid. The size of this network is determined in large part by the maximum (or "peak") electricity demand at each network level. Peak demand is correlated with extreme temperatures and diurnal patterns; for example, the 2023 peak for the New England region occurred on September 7 at 5:00 PM, with an average temperature of 88ºF and 70ºF dew point [11], close to the end of the workday as millions of New Englanders returned home and turned on air conditioning units.

In many parts of the US, peak demand has tapered [12]. However, electrification – combined with growth in data center construction and clean energy manufacturing – is expected to reverse this trend [13]. If EV owners plug in their vehicles upon returning home and heat pumps operate unmitigated during the hottest and coldest days of the year, peak demand is projected to grow rapidly [14][15]. This is expected to impact various portions of the electricity grid, from aggregate peak demand at the generation and high-voltage transmission levels down to peak demand on various distribution feeders and "semi-collective" groups of feeders [16].

To meet the expected growth in peak demand, electricity utilities are already making plans to expand delivery capacity. For example, in Massachusetts, the two largest investor-owned utilities – Eversource and National Grid – recently filed plans to invest over $10B for distribution infrastructure upgrades to support electrification [14][15]. Demand-driven investment costs will be passed through to grid users via electricity rates, which may exacerbate energy burdens and (paradoxically) disincentivize electrification [17].

In utility plans and in the modeling literature, a narrative is emerging that rapid peak demand growth is an inevitable consequence of electrification and that electrification, as a result, will increase electricity rates. However, this is only one possible path. Electrification, if managed to efficiently utilize existing infrastructure, can apply downward rate pressure. We refer to this phenomenon as "beneficial electrification." [1] One study by the California Public Utility Commission found that "the increase in electricity sales from electrification may outweigh the costs of distribution investments," a benefit to not just those who adopt EVs and CCHPs but all grid users [18]. Yet the structure of electricity rates today is not conducive to this beneficial outcome.

1.2 How Rate Design Impacts Electrification

When households consider whether to adopt EVs and CCHPs, one determinant is the total cost of ownership compared to conventional fossil fuel appliances [19][20]. If a household cannot save money over a reasonable time period, they will have little incentive to electrify.

[1] While "beneficial electrification" is often used to describe the broad set of environmental and cost benefits associated with electrifying various end uses, we define it narrowly to mean electrification that achieves a reduction in the average cost of electricity for all network users.

	Chevrolet Bolt (EV)	Chevrolet Equinox (ICE)
MSRP	$33,000	$24,000
IRA Tax Incentive	-$7,500	
5-year Fuel/Electricity Cost	$2,990	$6,400
Total	**$28,490**	**$30,400**

Figure 1.1: Difference in simplified 5-year total ownership cost between an EV and a comparable internal combustion engine vehicle. Maintenance costs are omitted.

Total cost of ownership consists of the cost of the equipment itself (inclusive of rebates), installation, and the cost of operating the equipment over its lifetime. EVs today cost more up front than conventional gasoline vehicles but experience lower operating costs due to the positive gap between the cost of electricity and gasoline [21]. Figure 1.1 shows a simple comparison of the 5-year ownership costs of an EV versus a comparable internal combustion engine vehicle driven for 12,000 miles per year, assuming manufacturer-listed prices and efficiencies [22], using US nationwide average gas ($3.66/gallon) [23] and electricity ($0.15/kWh) [24] prices as of January 2024.

CCHP systems have already achieved cost parity with conventional heating and cooling solutions for *new* construction [25]. But the economics are less favorable for retrofit installations, especially in areas connected to natural gas infrastructure where electricity costs are relatively high. In Massachusetts, for example, at current electricity and gas prices, it is less expensive to heat with natural gas once the outdoor temperature falls below 35F [26], and a household switching to all-electric heating can expect to spend more per year in operating costs [27]. With a negative cost gap, heat pump installations are far behind state targets [28]. By contrast, in Maine, which has a similar (if not less favorable) climate but where the dominant heating fuel is oil, over 100,000 CCHP systems have been installed, exceeding the state's ambitious targets [29]. These examples and prior research (e.g., [19]) provide evidence that electricity cost is a key determinant for CCHP adoption.

If we accept that the cost of electricity will play a central role in influencing the speed of electrification, we need to consider how consumers pay for electricity. Figure 1.2 shows a standard residential bill. The costs are broken into several categories – distribution, transmission, supply, etc. - described in Table 1.1.

Distribution and transmission together represent the cost of delivering electricity, as opposed to generating electricity, which is represented by the generation service charge (Category 1), and other policy costs (Category 5), which pay for policy-driven initiatives like renewable energy deployment and energy efficiency.

In this thesis, we focus on the distribution portion of the bill, which accounts for 26% of customer costs on average [30]. For investor-owned utilities (IOUs), which serve 72% of US electricity customers [31], distribution costs are regulated by each state's public utility commission (PUC), detailed in Chapter 2. In most of the US, distribution network costs are recovered from residential customers through "flat volumetric" electricity rates, or tariffs.

Supplier (CAMBRIDGE COMM ELEC DIRECT ENERGY)			
Meter [redacted]			
Generation Service Charge	1	172 kWh X .14810	$25.47
Subtotal Supplier Services			$25.47
Delivery			
(Rate 01 R1 RESIDENTIAL)			
Meter [redacted]			
Customer Charge	2		$10.00
Distribution Charge	3	172 kWh X .09434	$16.23
Transition Charge		172 kWh X -.00037	-$0.06
Transmission Charge	4	172 kWh X .04052	$6.97
Revenue Decoupling Charge		172 kWh X .00006	$0.01
Distributed Solar Charge	5	172 kWh X .00800	$1.38
Renewable Energy Charge	5	172 kWh X .00050	$0.09
Energy Efficiency	5	172 kWh X .02334	$4.01
Subtotal Delivery Services			$38.63
Total Cost of Electricity			**$64.10**

Figure 1.2: Example residential electricity bill (the author's bill), with major charge categories labeled. We omit consideration of the transition and revenue decoupling charges, which are not universal among US utilities and account for a very small portion of total costs.

Table 1.1: Description of major categories of charges on residential electricity bills

Category	Charge(s)	What the charge pays for
1	Generation Service	The cost of generating electricity, sometimes called the supply charge
2	Customer	Fixed costs including overhead (salaries, office space, etc) and metering equipment
3	Distribution	The cost of building and operating the low-voltage distribution grid
4	Transmission	The cost of building and operating the high-voltage transmission grid
5	Distributed Solar Renewable Energy Energy Efficiency	Public policy programs to promote conservation and deployment of clean energy

Flat meaning that the price is the same at all hours (i.e., time-invariant) and volumetric meaning that consumers pay based on their total consumption (per-kWh) over the course of a billing period.[2] Under flat volumetric rates, someone who consumes 200 kWh in a month will pay twice as much as someone who consumes 100 kWh. However, the costs underlying those charges depend on other factors besides total monthly consumption. Many utilities' distribution costs are fixed in the short run, reflecting past investments, and in the longer run are driven by the need to make incremental investments to handle periods of higher kW demand [32].

This misalignment between the drivers of increasing network costs and how those costs are recovered from consumers presents two major problems:

1. Under flat volumetric network tariffs, consumers do not receive any information about when the network is congested. This makes it more likely that newly electrified load (e.g., from EVs and CCHPs) will trigger network investments, whose costs are borne by all consumers in the form of higher rates.

2. Flat volumetric network tariffs provide no opportunity for consumers to reduce their costs by shifting the timing of consumption to periods when the network has excess capacity and marginal delivery costs are negligible. This has a negative impact on the economics of electrification.

For many years, a flat volumetric tariff was the only option for utilities to collect money from customers. Analog electricity meters measure only total consumption, not the timing of that consumption. But advanced meters can measure and communicate consumption at sub-hourly intervals, enabling "time-varying" rates where the price to consume electricity changes

[2] We use the terms "volumetric" and "per-kWh" interchangeably. Flat volumetric tariffs are also widely used to collect transmission and generation costs, but we focus only on the design of distribution network tariffs in this thesis.

depending on the hour, day, and/or season. Internet-connected devices, like EV charging stations and smart thermostats, make it simple for consumers to schedule consumption in response to these rates. Today, while approximately 73% of residential customers in the US have advanced meters [33], only 10% are enrolled on time-varying tariffs [34].

There is broad consensus that flat volumetric network tariffs are not cost-reflective [32] and discourage electrification [35].[3] There is a significant body of research recommending alternatives that more accurately reflect the true cost of consumption; as technology has improved, these proposals have grown increasingly complex, relying on such mechanisms as real-time auctions and autonomous home energy management agents. Yet US utilities and regulators have largely ignored these proposals; flat volumetric rates continue to prevail. This gap between what economists agree to be theoretically optimal rate designs and how rates are designed in practice can be partially explained by the regulatory framework dominant in the US today. Under cost-of-service regulation, IOUs have no incentive to offer alternative rates (discussed in Chapter 2). And regulators are hesitant to impose changes that might confuse customers or create large winners and losers compared to the status quo. This barrier highlights the need for simple solutions that consumers understand, that offer protections against large bill increases, and that do not rely on utilities to be active participants in managing load (against their own financial interest).

PUCs in California, Hawaii, Missouri, Colorado, and Michigan have illuminated a path forward by mandating that utilities offer per-kWh time-of-use (TOU) rates as the default. We review these initiatives in Chapter 4. This is a step in the right direction towards reflecting the underlying marginal cost of electricity delivery. But while TOU rates can improve the short-to-medium term economics of electrification, they may actually exacerbate peak demand growth and subsequent network investment. Other initiatives in the US to reduce the cost of electrification, most notably California's Income-Graduated Fixed Charge (IGFC), have been met with fierce opposition by solar and energy efficiency advocates. If we look outside the US, primarily in Europe, we find alternative approaches to tariff design that have the potential to reduce the marginal cost of electricity for consumers electrifying their heating and transportation *and* help defer network upgrades, which delivers benefits to all grid users.

1.3 Central Question and Thesis Outline

Under flat volumetric rates prevalent today, utilities are projecting significant network investments due to electrification, especially for the distribution grid. These investments will be recovered from all grid users through electricity rates. An increase in the cost of electricity will not only raise energy burdens broadly, but also threaten the positive gap (or

[3]Unless otherwise stated, the term "network tariff" in this thesis refers exclusively to the distribution network tariff. Despite our narrow focus, many of the proposed tariff-based solutions to deferring or avoided distribution investments can also be leveraged for transmission and generation constraints. A recent report by DOE projects a shortfall in generating capacity of 200 GW by 2030 to meet nationwide peak load [36]. Demand flexibility (i.e., devices acting in response to well-design tariffs) can help meet this gap; a recent study by Lawrence Berkeley National Lab found that price-based demand response is the most cost effective planning option for bulk system reliability [37].

exacerbate the negative cost gap) between electricity and fossil fuels, which will risks slowing decarbonization progress. Attempts to reform electricity rates in the US to promote electrification have primarily addressed symptoms of poor rate design, not their underlying causes, and have faced opposition from ratepayer advocates and consumer protection organizations. This opposition stems in part from the concern that vulnerable households will pay more under new rates because they cannot shift the timing of their consumption. There is an emerging narrative that rate reform is a zero-sum game; regulators can either protect vulnerable customers or encourage electrification, but not both. In this thesis, we challenge that perception: **can well-designed distribution network tariffs deliver a win-win, reducing costs for households that adopt EVs and/or CCHPs and households that cannot yet afford to electrify?** To answer this question, we calibrate a series of case studies in which we model household responses to different electricity tariffs under increasing levels of electrification. We consider the flat volumetric rates prevalent today, time-of-use rates recently implemented as the default in several states, and alternative rate designs that have already been implemented widely outside the US and which can be imposed by PUCs without specific legislative action. In each scenario, we assess the total network costs, economics of electrification, and distributional impacts on different household groups.

While many previous studies focus on the impacts of electrification on transmission and generation needs (e.g., [38], [39]), there has been relatively little analysis on the distribution grid under alternative tariff scenarios. Yet distribution, especially residential feeders with low load diversity, is where the majority of upgrades related to electrification are expected to occur [40]. Among studies focusing on the distribution grid, many rely on direct load control to reduce coincident peak demand from EVs and CCHPs, but this has not been widely implemented and many utilities in the US have no financial incentive to pursue direct load control. We address these barriers in Chapter 7. We are concerned that as the technical capabilities of load management evolve, advocates and regulators will ignore simpler solutions to harvest the low-hanging fruit. We believe direct load control, along with distributed generation and storage, will serve an important purpose in mitigating the need for expensive capital investments. But these are not substitutes for sound tariff design, which can be implemented at very low cost due to the existing metering infrastructure.

The central thesis question is particularly relevant for public utility commissioners who have a statutory obligation to regulate utilities in such a way that provides reliable service at least cost, ratepayer advocates who represent the public interest, climate advocates working to accelerate electrification, and state lawmakers focused on achieving climate, energy equity, and affordability targets who can influence PUC decision-making through legislative action if PUCs do not take the initiative themselves. Electricity rates are an often-overlooked barrier to decarbonization that do not require permitting change, extensive funding, or technology evolution. Using existing technology and existing statutory authority, every US state can undertake rate reform today. Our recommendations offer a path to removing one key barrier to rapid electrification while protecting all grid users from higher bills.

This thesis is organized as follows. Chapter 2 provides a brief background on utility regulation. Chapter 3 reviews the academic literature on electricity rate design and electrification impacts. Chapter 4 explores initiatives in both the US and Europe to replace flat volumetric rates. Chapter 5 presents the methodology for two case studies that examine performance of alternative rates against evaluative criteria. Chapter 6 presents the results of our case studies. Chapter 7 summarizes and discusses the policy implications of our results. Chapter 8 concludes and offers recommendations for public utility commissions.

Chapter 2

Background on the Electric Power Sector and Cost of Service Regulation

> "Free competition, the very basis of the modern social organization, superseded almost completely medieval restrictions, but it has just come to be recognized that the process of free competition fails in some cases to secure the public good, and it has been at last admitted that some control is necessary over such lines of industry as are affected with a public interest."
> - Bruce Wyman [41]

This chapter provides background context on the electric power industry and the cost of service regulatory model. This context helps inform our methodology and is important for understanding both past and future considerations for rate design.

2.1 The Electric Power Sector in the US

We start with a brief overview of the structure of the electric power sector in the US today. The physical infrastructure comprising the electricity sector can be divided into three functions: generation (converting various forms of energy into electricity), transmission (transporting electricity across long distances at high voltage), and distribution (delivering electricity to homes and businesses at low voltage). Among US states, there is considerable diversity in the type of entity that provides each function, with two categories of distinction outlined below: ownership structure and level of vertical integration. The term "electricity utility" is typically used to describe any entity involved in transmission and/or distribution, regardless of its involvement in generation. Entities that own only generation are typically called independent power producers (IPPs).

2.1.1 Ownership Structure

In the US, there are three models for utility ownership: investor-owned (IOU), publicly-owned (federal, state, or municipal), and cooperative member-owned. IOUs serve 72% of US electricity customers while public and cooperative utilities serve the remaining 28% [31]. Among IOUs, some are publicly traded while others are privately held. The vast majority of public utilities are municipally owned. Notable exceptions are the Tennessee Valley Authority (federally-owned), Bonneville Power Administration (federally-owned), New York Power Authority (state-owned), and Nebraska Public Power District (state-owned). Investor-owned utilities are regulated at the state level. Municipally- and cooperatively-owned utilities are often exempted from state regulation. In this thesis, we are concerned primarily with the the distribution function of investor-owned utilities. However, while most of the recommendations in this thesis are directed at state regulators, they could equally apply to municipal and cooperative utility board members.

2.1.2 Level of Vertical Integration

Fully vertically integrated utilities own and operate generation, transmission, and distribution infrastructure. They are the sole entities responsible for balancing supply and demand within their territories to ensure system reliability. Examples include Georgia Power (Georgia) and Xcel Energy (Colorado).

In the 1990s and early 2000s, several states passed electricity sector restructuring laws that required vertically integrated utilities to divest themselves of generation assets [42]. At the federal level, FERC Order No. 888 (issued in 1996) required utilities to file non-discriminatory open access transmission tariffs, removing a competitive barrier for third-party generators to interconnect with the transmission network. Shortly thereafter, FERC Order No. 2000 (issued in 1999) led to the voluntary formation of independent non-profit entities responsible for operating the transmission network, planning transmission upgrades, and administering competitive wholesale electricity markets. There are seven of these independent system operators (ISOs) in the US, which may span one state (e.g., NYISO, CAISO) or several (e.g., MISO, PJM). With the exception of ERCOT, ISOs are regulated by the Federal Energy Regulatory Commission (FERC), which approves market design and transmission access tariffs. There are two types of utilities operating within ISO service territories: 1) "wires-only" utilities, which own only transmission and/or distribution infrastructure. Examples include National Grid (Massachusetts) and Commonwealth Edison (Illinois); 2) utilities that are permitted to own generation assets in addition to transmission and distribution, but whose generation assets are dispatched economically by the ISO. Green Mountain Power (Vermont) and PacifiCorp (California) are two such examples, which purchase some portion of their electricity supply from the wholesale market.

In 13 states and the District of Columbia, restructuring applied not only to generation but also the supply component of the bill. Customers in these states are able to select their electricity supplier [43].[1] Suppliers do not own or operate physical infrastructure but purchase electricity on behalf of their customers. In all states except Texas, the local distribution utility is designated as the default supplier [44]. Suppliers are not subject to price or profit regulation [45]. While all states with retail choice fall within ISO territories, not all states in ISO territories permit retail choice (e.g., Vermont). We turn now to the origins of regulation in the electric power sector.

[1] As retail choice is sometimes called energy deregulation, there is a common misconception that these states deregulated all utility functions. This is not true; transmission and distribution remain tightly regulated in states with retail choice.

2.2 Origins of Regulation

Electricity distribution, or delivery, is a geographical natural monopoly. The industry is characterized by high sunk capital costs and significant economies of scale; the more network users in a particular geographical area, the lower the average price because fixed infrastructure costs are spread over higher consumption [46].

Unlike most industries, competition in electricity distribution drives costs up. When there are multiple electricity providers in one area, geographic economies of scale cannot be fully captured due to duplication of distribution facilities in the same geographic area. The summary judgment in Idaho Power & Light Co. v. Blomquist et al. (from 1914) offers a helpful hypothetical example to illustrate this phenomenon:

> "An existing utility has already expended, say, $1,000,000 in the power plant and transmission lines and distribution system in a town. Another utility, coming in, must also provide a power plant and transmission lines and a distributing system. If there is to be unrestricted competition, then the later distribution system must cover the same area as that of the older one. If it costs the same money, then there is an additional $1,000,000 expended in a town where a $1,000,000 system would be amply sufficient. There would be two sets of poles and transmission wires in the streets, the construction and keeping in repair of which would necessarily interfere with and obstruct the free use of the streets by the people more than one set of poles and wires; and two sets of electrical wires in a city would necessarily increase the danger to the lives and limbs of the people, and thus interfere with the peace, health, and welfare of the community."[2]

In light of this fact, as early as 1905, state legislatures passed laws establishing quasi-judicial statewide commissions (public utility commissions, or PUCs) to regulate investor-owned electricity utilities [47].[3] The legality of state regulation over private industries "affected with a public interest" (as quoted above in Wyman [41]) was enshrined in the landmark 1876 US Supreme Court case, Munn v. Illinois.[4] Regulation over electricity prices existed prior to the creation of state PUCs but consisted primarily of municipal franchise contract agreements [45]. The formation of PUCs shifted oversight of private electricity utilities to the state level. As it relates to electricity utilities, PUCs have two primary roles: 1) controlling market entry by issuing certificates of public convenience that grant exclusive franchise rights for IOUs to serve a particular geographic area; and 2) determining the prices IOUs are allowed to charge.

Today, PUCs are comprised of 3-7 commissioners and professional staff. Commissioners serve terms between 4-6 years and are either appointed by the governor or state legislature or publicly elected. PUCs regulate not only electricity utilities but also those operating in the telecommunications, water, and waste water industries.

[2] *Idaho Power & Light Co. v. Blomquist et al. 26 Idaho 222 (1914)*

[3] We use PUC as a generic term to refer to the state agency that regulates privately-owned electricity distribution utilities. In some states, these agencies go by different names, e.g., Public Service Commission or Department of Public Utilities.

[4] *Munn v. Illinois 94 U.S. 113 (1876)*

2.3 Cost of Service Regulation and Rate Cases

In the US, regulators exercise price-setting authority over IOUs via a framework known as Cost of Service Regulation (COSR).[5] Under COSR, a utility is permitted to recover prudently incurred capital and operating costs, plus a regulated rate of return on invested capital. The prudency standard was first proposed by Supreme Court Justice Louis Brandeis in a 1923 dissenting opinion.[6] Cost recovery is determined in a formal public adjudicatory process known as a rate case.[7]

A rate case consists of two core components: 1) determining the amount of money the utility is allowed to recover (the revenue requirement) and 2) allocating the revenue requirement to customers via rates (rate design). Historically, rate cases are either initiated by IOUs or occur at regular intervals (e.g., 3-5 years).

In a rate case, the utility submits its target revenue requirement along with supporting evidence. The public interest is represented by a "ratepayer advocate," which may be the state attorney general's office, an independent state agency, or a division within the PUC. Other individuals and organizations (e.g., trade groups, large industrial customers, environmental advocates) can formally intervene. Both the ratepayer advocate and intervenors can submit testimony, cross-examine witnesses in public evidentiary hearings, and offer competing analysis to challenge utility expenditures and modeling assumptions.

Regulators consider all evidence entered into the record and determine which costs to include in the revenue requirement. Regulators can disallow costs that they determine are excessive or the result of imprudent managerial decisions, although disallowances are typically small [45]. Once the revenue requirement is determined, regulators decide how to allocate the amount among customer classes (residential, commercial, industrial) via rates (i.e., tariffs) [48]. In Federal Power Commission v. Hope, the US Supreme Court ruled that PUCs are not required to use any one specific formula for setting rates so long as those rates are "just, reasonable, and not unduly discriminatory".[8] This granted regulatory commissions latitude to exercise discretion in ratemaking, balancing the public good (reliable service at least cost) with fair compensation that allows IOUs to operate successfully and attract capital.

In practice, regulators typically allocate the share of the total revenue requirement to each class commensurate with the cost to serve that class [45]. Additional principles including simplicity and stability have guided regulators for decades [49]. Rate cases conclude with a final decision issued by the PUC (often via simple majority vote among the commissioners), which sets the new tariffs starting at a specified future date.

[5] As this thesis deals with distribution costs, we do *not* distinguish between IOUs that have been restructured through deregulation of generation and/or retail supply (e.g., Eversource in Massachusetts) and IOUs that remain vertically integrated (e.g., Georgia Power in Georgia).

[6] Southwestern Bell Telephone Company v. Public Service Commission of Missouri 262 U.S. 276 (1923)

[7] The brief summary in this section was inspired by Joskow and Schmalensee [45], which provides a more complete discussion of COSR and the mechanics of rate cases in practice.

[8] *Federal Power Commission v. Hope Natural Gas 320 U.S. 591 (1944)*

2.4 Limitations of Cost of Service Regulation and Alternatives

With perfect information, COSR can replicate the pressures provided by market competition, allowing utilities to recover only efficiently-incurred costs and earn a return on investments equal to the cost of capital [50]. However, in practice, resource limitations and information asymmetry between the regulator and IOU can lead to imperfect regulation and performance problems. IOUs may leverage their superior information during rate cases to increase their profits [51]. This issue is even more prevalent if the utility can influence the regulatory process [52], [53]. Research by the Energy and Policy Institute has revealed a pattern of utility involvement in state elections and policy development through campaign contributions and lobbying, respectively [54]. In perhaps the most extreme case, a utility was fined $230 million for a bribery scheme that led to multiple indictments on federal racketeering charges [55]. More commonly, however, utilities aim to influence regulation through legal means by donating (either directly or through their employees or political action committees) and by supporting industry associations and similar groups that engage in lobbying activity on their behalf [54]. These political activities may further compromise the regulator's effectiveness in protecting customers from excessive rent-seeking by the IOU.

One other limitation of COSR is that it prima facie biases IOUs towards capital expenditures (which are eligible for a rate of return) over operating expenditures (which are simply passed through). This was identified by Averch and Johnson studying an idealized form of COSR with no information asymmetry or regulatory lag (i.e., the gap between rate cases) [56]. Empirical studies, which focus mostly on generation investments, show mixed results on the presence of capital bias in practice ([57], [58], [59]). Joskow and Schmalensee provide a concise summary of the literature on capital bias: "We believe that it is likely that the capital bias is articulated most importantly as a bias toward owning capital assets rather than buying services from third parties, since the costs of many of these services are treated as cost pass-throughs in the regulatory process, are not impacted by regulatory lag, and provide no profit opportunities" [45]. Under COSR, there are also no profit opportunities presented by solutions that *avoid* the need for capital investments that expand delivery capacity, including rate design. An IOU has little incentive to reduce its costs if it believes it is unlikely those costs will be disallowed.

Incentive regulation, also known as Performance-Based Regulation (PBR) in the US, attempts to address the limitations of COSR, especially when there are large regulatory lags [45]. The goal of incentive regulation is to induce regulated entities to employ their superior knowledge to reduce costs [50]. In its most basic form, revenue-cap regulation, the utility's revenue is capped (determined based on historical costs and comparisons with other utilities in similar geographies) and the utility earns a profit based on the gap between the allowed revenue and actually-incurred costs [52], [60]. Variations on this basic idea include menus of contracts (where the utility is allowed to choose among several regulation plans), profit sharing mechanisms, and TOTEX-based approaches (in which there is no accounting distinction between capital and operating expenses). These are described in detail in Brown and Sappington [50] and Joskow and Schmalensee [61].

In the US, PBR has focused on three components: multi-year rate plans (which adjust rates based on external indices), revenue decoupling mechanisms (which eliminate incentives against promoting energy efficiency), and performance incentive mechanisms that adjust upward or downward the utility's rate of return base on its performance against predetermined metrics (e.g., average outage duration and average time to interconnect customer generation) [45]. PUCs have adopted these measures to varying degrees, with Hawaii generally recognized as the leading state on PBR. However, even in states with some or all of the three PBR components, COSR (along with its associated incentives) remains the underlying regulatory framework. Under both PBR and COSR, IOUs are typically also subject to minimum performance standards to ensure that they do not underinvest or overinvest in the system.

While PBR is outside the scope of our analysis, we mention it because it can be an effective complement to the rate interventions we propose. Regulators should leverage all tools at their disposal to achieve state policy mandates, including PBR.

2.5 The Link Between Rate Design and Network Investments

During rate case proceedings, utilities typically submit forecasts of expected electricity demand for the subsequent 10-20 years. These forecasts inform future investments, which are recovered from consumers via rates. When demand is growing, utilities must expand delivery capacity to continue to provide reliable service. For regulators, forecasts help determine whether investments are prudent.

Utilities forecast both the expected annual electricity consumption and the instantaneous maximum consumption (i.e., peak demand) at each network level. The latter is more relevant for distribution network investments, where equipment (substations, transformers, etc) is sized to accommodate peak loads.

A comprehensive analysis by Carvallo et al. [62] shows that utilities tend to overforecast peak demand. Dyson and Engel [63] attribute this tendency (which they estimated to be +12% for 10-year-ahead forecasts) to two factors: asymmetric risk (over-forecasting demand leads to excessive costs, while under-forecasting demand may lead to service disruptions) and the link between demand forecasting and capital investments.

Historically the main driver for network investment was growing demand [32]. In the last two decades, peak demand growth in the US has slowed due in part to slowing population growth, increasingly strict appliance efficiency standards, the growth of rooftop solar, and a transition away from an energy-intensive manufacturing economy to a service economy [62]. Economy-wide electrification, the recent boom in clean energy manufacturing, and growth in data center demand fueled by artificial intelligence applications are expected to reverse this trend and become significant drivers for new network investment [64], [13]. While EV and CCHP penetration rates are low today, utilities are pointing towards existing government incentives and anticipated phase-out mandates to forecast rapidly increasing peak demand, which will necessitate network investments to maintain reliability and support further electrification [14], [15].

These demand forecasts are influenced indirectly by rate design. In most states, utilities forecast demand from residential customers assuming that they continue to pay flat volumetric rates. Under flat volumetric rates, consumers have no reason to avoid consuming electricity during times when the network is congested, contributing to peak demand growth and necessitating network investments, which customers ultimately pay for. Carvallo and Schwartz [37] found that utility integrated resource plans systematically ignore rate design as a tool to avoid the need for building new delivery capacity.

There is ample evidence that consumers respond to price signals when available and that these responses can meaningfully reduce peak demand [65], [66]. Faruqui and Sergici [66] find that the response is consistent across income groups, and price signals are even more effective when consumers have enabling technology that can respond automatically without the need for behavioral intervention. If cost-reflective price signals existed, EV and CCHP users would likely change the timing of their consumption in a way that avoids or defers the need to expand delivery capacity, even as total consumption grows. Yet COSR does not provide incentives for utilities to promote rates that reflect the long-run cost of electricity delivery. In fact, to the extent these rates may reduce peak demand and the level of efficient investment [50], utilities have an implicit disincentive to transition away from the status quo in rate design.

Kavulla [33] proposes a fix to this shortcoming of COSR, recommending that regulators (not utilities) decide on rate structure and design rates in a way that consumers are exposed (at least partially) to network cost drivers, thereby "activating" flexible demand. Regulators in California, Colorado, Hawaii, Michigan, and Missouri have done just that, by implementing time-of-use rates as the *default*, which we outline in Chapter 4. These rates have had high retention rates even though customers are free to opt out and choose to pay flat volumetric rates [34]. Compared to other solutions that mitigate network investments, including direct load control and battery storage deployment, it is relatively simple for regulators to monitor that utilities are in compliance with rate design reforms.

This chapter outlined the structure of the electric power sector in the US and the cost of service regulatory framework. In summary, while generation and (to a lesser extent) supply have been deregulated in many states, distribution remains characterized by geographic monopolies regulated at the state level subject to cost of service regulation. Under cost of service regulation, utilities recover prudently incurred costs and earn a regulated rate of return on capital investments. While some states have adopted elements of incentive regulation, COSR remains the dominant framework in the US. Under COSR, utilities have no financial incentive to reduce the need for capital investments. This poses a key challenge to beneficial electrification; as demand-driven capital investments are allocated to all grid users, this risks eroding the positive cost gap between electricity and fossil fuels and increasing energy burdens for vulnerable households.

While incentive regulation has been shown to enhance the productivity of IOUs [50], achieving beneficial electrification does not necessarily require a shift away from COSR, which could take years to implement. Rate design offers a near-term solution that can address the urgency of both decarbonization and electricity affordability. Regulators have a statutory obligation to design rates that are just and reasonable. We believe flat volumetric rates, which are based on outdated assumptions about consumers' willingness and ability to respond to prices, no longer meet this standard. There is overwhelming evidence that time-varying rates (complemented by enabling technology) can reduce the need for incremental network investment by reducing peak demand and making more efficient use of existing infrastructure. Without specific authorizing legislation, regulators have imposed time-varying rates in five states, offering a blueprint to implement the rate design recommendations presented in this thesis.

Chapter 3

Literature Review and Research Contribution

In this chapter, we provide a summary of the academic literature on the impact of electrification on distribution grids and distribution network tariff design. At the end of this chapter, we discuss our research contribution.

Much of the existing literature at the intersection of electrification and network tariff design falls into two broad categories:

1. Studies on the grid impacts of electrification under the assumption of flat volumetric tariffs (i.e., price-inelastic demand)

2. Studies on alternative tariff designs using historical consumption data or in the presence of customer adoption of rooftop solar and battery storage

We review these two categories below.

3.1 Impacts of Electrification Under Flat Volumetric Tariffs

3.1.1 Heat Pump Impacts

Studies on grid and cost impacts of CCHP adoption typically assume that the heating equipment is used to achieve a constant indoor setpoint temperature. Waite and Modi [67] study distribution grid capacity to support heating electrification, finding that the existing capacity could support 53% electric heating (by delivered units of energy). This figure climbs to 97% if homes maintain backup fossil heating for extreme temperature days. Vaishnav and Fatimah [68] consider the household economic and carbon impact of electrifying space heating across the entire US; with existing electricity rates, only in states where resistive electric heating is prominent are savings achieved. White et al. [69] analyze the generation and transmission scale impacts of heat pump adoption in Texas; using the same open-source residential electricity consumption database that we employ in this thesis, the authors find that full electrification increases residential peak demand by 36% (12 GW). Wilson et al. [5]

study the cost and benefits of CCHP installation across all 50 US states and conclude that the technology is cost-effective in 65 million homes (inclusive of up-front installation costs). Simulating distribution networks and building heating demand for a region in rural Belgium, Protopapadaki and Saelens [70] find overloading and voltage issues above 30% penetration. Lee and Zhang [71] find that smart thermostats can severely increase winter peak heating demand through load synchronization.

These studies reveal significant geographic variation. In summer-peaking areas, heating electrification may actually reduce peak loads because heat pumps (which can operate in reverse as air conditioners) are more efficient than existing window air conditioning units. Conversely, in colder climates, heating electrification is projected to increase both system-wide peak demand [72] and local distribution peak demand [70].

3.1.2 Electric Vehicle Impacts

In transportation, many analyses on EV charging envision that drivers charge immediately upon returning home or as needed at public and workplace charging stations. Muratori [73] discovers that even if system-wide impacts are small in the near term due to low overall EV penetration, clustered EV adoption may require widespread upgrades for distribution grid equipment like small-scale transformers. Huang and Infield [74] employ Monte Carlo simulation and find that even at 20% adoption, EV charging increases peak demand on a representative low voltage feeder by 30%. Elmallah et al. [75] study cost impacts of distribution grid upgrades triggered by residential electrification in Northern California, which are dominated by EV charging. Coignard et al. [76] find that 60% of the feeders in the San Francisco Bay area would reach or exceed their maximum loading limit under an uncontrolled charging scenario where each household has one EV.

More recently, Needell et al. [77] estimate electricity demand curves at high penetrations of EV and rooftop photovoltaic (PV) systems in New York, NY and Dallas, TX, finding that workplace charging and delayed overnight charging are effective strategies for reducing peak demand and the need for investment in distribution capacity. Gschwendtner et al. [78] assess the impact on local system peak of plug-in behavior – when and for how long drivers decide to charge. Powell et al. [79] use charging data from a charging network operator to show how charging behavior can either complement or exacerbate renewable generation deployment issues.

Nour et al. [80] review the negative impacts of uncontrolled EV charging, including increases in peak demand and overloading of network components, and how those impacts can be mitigated by delayed and controlled charging techniques. Kevala [17] performs a bottom-up load forecasting and system impact study for EV charging in California, estimating up to $50 billion in traditional electricity distribution grid infrastructure investments by 2035 under unmitigated charging scenarios. Finally, Steinbach and Blaschke [81] show that higher-income individuals tend to have uncontrolled charging schedules that align more closely with local network peaks than medium- and low-income individuals, posing a serious equity concern (since investments are recovered indiscriminately among all customers with flat volumetric rates).

There is less geographic variation in EV charging demand compared to electric heating, but cold temperatures impact battery efficiency and auxiliary energy consumption for cabin conditioning [82]. Charging activity in urban areas where dedicated parking is uncommon is less well-understood, but there has been progress recently at simulating this segment [83].

Efforts to understand the grid impacts of residential electrification under flat volumetric tariffs have provided important "worst case" scenarios to motivate an examination of electricity rates. When households have no incentive to change the timing of their consumption, EV charging and CCHP-related demand is likely to increase peak demand (both locally and at a bulk-system level), requiring extensive network upgrades. One Massachusetts distribution utility forecasted that adoption of these two technologies will increase coincident peak demand by 8 kW per customer, an increase of 250% compared to current peak demand values [14].

Many studies in this category typically perform "snapshot" analyses, looking at the peak hour of the year or a representative high-demand week. With the exception of a few papers (e.g., [5], [17]) they do not examine the longitudinal impacts on customers' costs due to electrification. They also offer little insight into system impacts if we expand the window of rate design possibilities and consider time-varying tariffs that consumers can react to, either through programmatic or behavioral changes.

Finally, some papers extend their analysis of electrification impacts by introducing top-down load control of EVs [76], [80], [84], [85], [86], [87] and heat pumps [88], [89], [90]. Load control is used to reduce peak demand by curtailing consumption or shifting consumption to hours with excess delivery capacity. Heat pumps are generally considered to be less flexible due to thermal comfort limits, but both devices can be shifted programatically without direct behavioral intervention. These analyses do not consider price-based coordination but instead direct management of devices by a utility or aggregator. Though not in every case, they also generally do not consider the regulatory context, incentives paid to participants, or consumer willingness to engage in control programs, only the theoretical potential of load control. While there is promising evidence (outlined in Chapter 4) that consumers accept frequent EV load control, we do not believe that it is a contemporary substitute for sound tariff design. Section 7.2.3 elaborates on this position.

3.2 Network Tariff Design in Theory

While energy economists have long understood that flat volumetric tariffs are inefficient, until recently there was not much political interest in addressing the problem. The metering technology made it difficult or impossible to measure hourly consumption, there was a strong status quo bias among regulators, and consistent load growth kept retail electricity prices relatively low. Because volumetric electricity consumption is correlated with income [91], legacy rates were somewhat progressive, which some stakeholders may have viewed as a positive feature not to be altered. High volumetric rates also encourage adoption of energy-efficient appliances, which was supported by environmental advocates.

Tariff reform (specifically distribution network tariff reform) has gained attention due to three major recent trends: the roll-out of smart meters, the adoption of rooftop solar PV under net metering programs, and residential electrification.

Aided by $8 billion of funding from the American Recovery and Reinvestment Act, many US utilities began rolling out smart energy meters in 2009 [92]. Today, over 73% of US households are estimated to have a smart meter [93], which allows utilities to collect consumption data at hourly or sub-hourly intervals. However, there is significant variation between states, even within the same region: Vermont has 99% smart meter adoption while in Massachusetts the figure is less than 10% [94].

In net metering programs, solar customers are charged for their net consumption (total consumed from grid minus total exported to the grid), typically calculated monthly. Under flat volumetric rates, solar customers can avoid paying not just supply costs but also network costs, even though they remain connected to the network and may not be generating solar during peak periods. Because sunk network costs are by definition unaffected by solar production, this creates a cost shift to customers who do not have solar PV systems [95]. And because solar adoption has been highly correlated with household income [96], there is an emerging equity issue associated with net metering programs. This has attracted much research interest (e.g., [97], [98], [99], [100]) along with regulatory initiatives aimed at designing successor programs to net metering. For example, California's recently-approved Net Energy Metering 3.0 tariff compensates solar customers for exported energy at the avoided cost rate rather than the full retail rate. This provides a clear incentive to align consumption with generation to avoid exports, or to install battery storage and charge during solar hours.

As states and nations have turned to electrification as a core decarbonization strategy, there is also a growing awareness that flat volumetric rates are a barrier to EV and CCHP adoption. Under a flat volumetric tariff that recovers both supply and network cost, the per-kWh charge substantially exceeds the marginal cost of generating electricity [35]. In Massachusetts today, it is cheaper to run a natural gas boiler than a heat pump at outdoor temperatures below 35F [26], and a customer who replaces their natural gas space heating with a CCHP system will likely pay more in annual energy costs, independent of the installed cost of the system itself [27]. These issues have prompted regulators and the academic community to rethink the historically-accepted practice of collecting network costs via flat volumetric rates.

A central objective of tariff design is to provide incentives for consumption while producing adequate revenue to recover the utility's costs. For a tariff to be efficient, it should be structured so that network users are charged according to the cost they impose on the system. This will provide incentives that limit overinvestment in the network. In addition, distribution network tariffs should be simple and predictable, non-discriminatory towards certain customer groups, and recover all regulated costs to ensure financial sustainability for the utility [32]. Flat volumetric tariffs violate many of these principles; Passey et al. [101] show that under time-invariant network tariffs, the costs consumers pay rarely reflects the costs they impose on the system. This leads to inefficient incentives for grid usage and to cost shifts between grid users. Yet there is also evidence that perfect cost-reflexivity may not be the ideal design; Hofmann and Lindberg [102] demonstrate that consumer responses become muted under increasingly complex tariffs.

In theory, the most efficient distribution network tariff contains two parts: a forward-looking charge that reflects the long-run marginal cost of upgrading the network at each location and a complementary fixed charge to recover the residual costs of past network investments [32], [103]. While there is consensus around this framework, there is considerable disagreement in the literature on how it should be interpreted to design distribution network tariffs in practice, with some focusing on increasing fixed charges and others focusing instead on reflecting the true cost of network upgrades in time-varying tariffs. Though few papers specifically address barriers to electrification, many make proposals that would reduce the operating cost of EVs and CCHPs by sending more efficient signals and/or shifting cost recovery away from volumetric charges.

Broadly speaking, the literature contains two categories of analysis on redesigning network tariffs: [1]

1. Backwards-looking studies that apply novel rates to static historical data (retroactive)
2. Optimization-based studies in which grid users can make decisions in response to new tariffs (proactive)

3.2.1 Tariff Design with Retroactive Analysis

Among retroactive analyses, there is considerable diversity in approach. Using annual data from California grid users, Borenstein et al. [100] experiment with shifting non-marginal network costs to a fixed charge. To improve equity, the authors argue for an income-graduated fixed charge (IGFC) similar to a progressive income tax. Using smart meter data from 100,000 grid users in the Chicago area, Burger et al. [105] recommend a two-part tariff with a per-kWh charge set equal to the social marginal cost of energy and an income-based fixed charge. Acknowledging that utilities collecting income information would be both burdensome and potentially unacceptable from a privacy perspective, Battle et al. [106] propose a fixed charge based on historical consumption, reasoning that past usage is a relatively good proxy for past costs users imposed on the system. Simshauser [98] suggests a three-part tariff (with fixed, volumetric, and capacity components) to mitigate cost shifts between solar and non-solar households in Queensland, Australia. Simshauser and Downer [107] find that households in financial hardship are the most adversely affected by flat tariffs and have the most to gain from a transition to cost-reflective network tariffs. Bergaentzlé et al. [108] study the distributional impacts of tariff reform in Denmark on different household groups, including income-based and those with EVs and heat pumps. Sergici et al. [27] use actual metered gas and electricity data from a utility in Massachusetts and advocate for demand charges and time-of-use volumetric charges to improve the economics of heating electrification. Kahn-Lang et al. [109] calculate bill savings from efficiency and electrification measures under flat and several time-of-use rates with varying peak:off-peak ratios. Küfeoğlu and Pollitt [110] examine the impacts of EV and PV adoption, concluding that the technologies have opposite effects: EV adoption drives tariff prices down while PV adoption increases rates. These papers typically treat network costs as sunk and apply the constraint of "revenue neutrality," meaning that the total amount of money collected by the utility is constant and customer end-use consumption is static. They do not consider outcomes where additional network investments are required to meet peak demand but can be avoided, reduced, or

[1] There is a third category that attempts to estimate consumer price-elasticity to time-varying rates using empirical evidence (e.g., [65], [66], [102], [104]). While these are valuable for understanding potential tariff impacts, they do not differentiate between load related to electrification and other household consumption and are not well suited for the new era of demand flexibility where consumers can respond perfectly with the aid of automated tools. Rather, they focus on behavioral changes.

deferred through appropriate tariff design. The assumption of zero marginal demand-driven distribution cost does not align with utility planning to support end-use electrification of transportation, buildings, and other sectors [14], [15].

Other "retroactive" studies consider the possibility of future network investment or load growth. Morell-Dameto et al. [111] apply a simple fixed charge to cover residual costs with a highly spatially- and temporally-granular per-kWh component that reflects forward looking network expansion costs, choosing Slovenia as a case study.[2] Using smart meter data from Danish consumers, Gunkel et al. [112] advocate for a two-part tariff that includes an individual peak charge and a system-coincident peak charge. Finally, Govaerts et al. [113] build a synthetic grid to investigate the "Long Run Incremental Cost" approach to calibrate network tariffs.

3.2.2 Tariff Design with Proactive Analysis

Papers in the proactive category use optimization techniques (typically single or bi-level linear programming) to calibrate tariffs based on consumer responses. These typically focus on adoption of solar or battery storage due to the interest in addressing equity impacts of policies like net metering. Abdelmotteleb et al. [114] consider four network tariff designs and simulate consumers' cost-minimizing responses, with the ability to purchase electricity from the grid or invest in onsite generation. The authors ultimately recommend a fixed charge plus a peak-coincident network charge based on each customer's demand during the annual peak hour. Schittekatte [115] uses a bi-level optimization to simulate how consumers with the option to invest in distributed energy resources (DERs) like solar PV may respond to three different network tariff designs. Nouicer et al. [116] similarly apply a bi-level optimization (whereby the utility maximizes aggregate social welfare and consumers maximize their own welfare subject to the network tariff) to explore curtailment as a form of demand flexibility. All three papers adhere to the European regulatory context, where utilities have an incentive to reduce operating costs. In contrast, US utilities operating under a cost-of-service regulatory framework would have no financial incentive to minimize capital or operating costs. The papers in this category also do not consider outcomes where customers increase net demand through EV and/or CCHP adoption.

There are a few recent exceptions, which consider the interaction between tariff design and electrification. Hoarau and Perez [99] study network tariff design in the UK in the presence of both DER (solar PV and batteries) and EV adoption using a non-cooperative game where network users seek to minimize their costs. The authors study fixed, volumetric, and capacity tariffs and conclude that EV adoption can mitigate the cost shift caused by PV and battery adoption. Similar to Küfeoğlu and Pollitt [110], Hoarau and Perez [99] find that tariffs that incentivize DER adoption stifle electrification and vice versa. Arlt et al. [117] simulate responses of HVAC systems in Austin, Texas to real-time tariffs during a full year. The authors find moderate savings potential ($39/customer/year); when all HVAC systems react in a coordinated fashion to the dynamic price it causes local congestion issues, which can be mitigated partially by supplementary demand management. However, the authors

[2] The approach in Morell-Dameto et al. [111] adheres to the "efficient ideal" advanced in Pérez-Arriaga et al. [32], which posits that forward-looking costs should be calculated precisely at each network node.

calculate rates in a cost-neutral way and do not consider network reinvestment (instead using assumed congestion prices). Bergaentzlé et al. [118] explore different tariff structures for a district heating system in Denmark, considering capacity charges, peak time rebates, and dynamic volumetric prices. The authors conduct a case study by minimizing operating costs from the perspective of the distribution utility and ultimately recommending adopting a dynamic tariff that reflects real-time grid conditions. Finally, Hennig et al. [119] lay out a framework for assessing network tariff performance, focusing on cost efficiency, cost recovery, and implementation burden. In a case study, the authors test four network tariff designs under EV adoption, where the distribution utility upgrades distribution transformers once they reach 95% of their capacity. The case study illustrates how to use the tariff assessment framework in practice, but it uses a sample of only 50 consumers in Germany and considers network tariffs in isolation, with no analysis of the interaction between network and energy tariffs.

3.3 Research Contribution

There has been only limited research on the design of distribution network tariffs in the presence of electrification and the grid impacts of electrification under time-varying tariffs. This thesis fills an important gap in the literature by modeling electrification under alternative tariff scenarios and focusing on the long-term cost impacts related to distribution network investment. Critically, we assume that the utility has no incentive to minimize operating costs, which reflects cost-of-service regulation prevalent in the US. We consider only bottom-up responses to tariffs published ex-ante by individual households acting independently to minimize costs (i.e., no coordination between households). We apply technology-agnostic whole-home tariffs that do not require additional metering. Our tariff choices are inspired by existing distribution network tariff designs in Europe (reviewed in Chapter 4), which seem largely to have escaped the attention of regulators and analysts in the US.

In our case studies, tariff prices evolve to collect the full revenue requirement as the network is expanded to accommodate growing load. Many existing studies consider tariff reform at a single point in time, which necessary creates winners and losers compared to the status quo as the same amount of money must be collected (i.e., there is a constraint of revenue neutrality). However, when we consider how a rate will impact future loads and network investment as customers respond to price signals, we can assess whether well-designed rates can deliver benefits for all customers, including those who have not yet electrified. Finally, we consider interactions between separately-designed energy and distribution network tariffs, which we have not encountered anywhere else in the literature.

The closest existing studies to this thesis are Satchwell et al. [120] and Li and Jenn [121], although neither study considers heating electrification. Satchwell et al. [120] look at the impacts of EV adoption on utility customers and shareholders. The authors model charging demand, estimate network upgrade and capacity expansion costs, and calculate the resulting average retail rates. They find that EVs reduce rates for all customers under a "low peak impact" scenario, but they consider only direct load control (not price-based coordination), assuming all customers continue to pay flat volumetric rates. Li and Jenn [121] use empirical EV charging data (including residential charging responding to TOU rates) to estimate that

California utilities will need to invest between $6 and $20 billion to upgrade distribution infrastructure between now and 2045, but that growth in consumption will outpace these investments and apply downward rate pressure of between $0.01 and $0.06/kWh. However, the authors do not consider tariff design, only the expected rate impacts under existing tariffs and the current revenue requirement.

In this chapter, we reviewed the academic literature on electrification impacts and network tariff design. We introduced our research contribution, which extends and addresses gaps in a small body of existing literature at the intersection of these fields. Table 3.1 shows how this thesis compares to existing research. This is not a complete list but a representative sample.

Table 3.1: Classification of network tariff design studies with an application to electrification

Author	**Technology**	**Geography**	**Coordination Mechanism**	**Considers Long Term Rate Impacts?**	**Duration**
Hoarau and Perez [99]	PV, EV	UK	Tariffs	No	1 year
Bergaentzlé et al. [118]	District heating	Denmark	Tariffs	No	1 year
Arlt et al. [117]	HVAC	Austin, TX	Tariffs	No	1 year
Hennig et al. [119]	EV	Germany	Tariffs	Yes	0-25 EVs
Satchwell et al. [120]	EV	Southern US	Control	Yes	30 years
Li and Jenn [121]	EV	CA	N/a	Yes	20 years
This thesis	EV, CCHP	US (MA, NC)	Tariffs	Yes	0-100% adoption

Chapter 4

Distribution Network Tariff Design in Practice: Approaches from the US and Europe

In this chapter, we first cover recent tariff reform efforts in the US, including "whole-home" and "electrification-specific" designs. Next, we review distribution network tariffs widely implemented in Europe, which serve as inspiration for our case studies.

4.1 Distribution Network Tariff Design in the US

In this section, we review recent tariff reform efforts in the US. While over 73% of residential consumers have smart meters capable of metering at sub-hourly intervals [93], only 10% are estimated to be subject to time-varying rates today [34]. Many utilities offer voluntary time-of-use rates, but these are not widely promoted. Recognizing that flat volumetric rates do not reflect underlying costs and that voluntary TOU rates are undersubscribed, several states have introduced alternatives. We highlight two types here: default TOU tariffs and electrification-specific tariffs.

4.1.1 Default Time-of-Use Tariffs

In 2020, California became the first US state to institute default TOU rates for all residential customers, with network and supply costs combined into a single, time-differentiated per-kWh charge. Customers were transitioned to either a 2-part or 3-part TOU rate; the timing of each period and the ratio of on-peak to off-peak price varied according to location and distribution utility. Those who wanted to remain on a flat volumetric rate needed to explicitly request to opt out. All new residential accounts starting in October 2020 have been placed on the TOU rate.

Other states have followed California's lead. After a multi-year Advanced Rate Design proceeding, in May 2023 Hawaii's PUC ordered the utility (Hawaiian Electric) to implement a default TOU rate by July 1, 2024. The TOU roll-out will be paired with a fixed charge reform intended to shift some of the utility's fixed costs to a non-variable charge and the introduction of a “grid access” fee proportional to each customer’s monthly maximum demand. This grid access fee is first instance of a demand charge being used for a *default* residential tariff in the US. We are aware of two instances where a demand charge is used a component of a *voluntary* residential tariff: 1) in North Carolina, Duke Energy’s RS tariff has a two-part demand charge, with one component calculated based on the maximum demand during the on-peak period (6:00 - 9:00 PM during the summer and 6:00 - 9:00 AM during the winter) and the other component calculated based on the maximum demand during all hours; 2) in Arizona, Arizona Public Service offers an opt-in TOU rate with a demand charge assessed based on the customer’s highest usage hour between 4:00 PM and 7:00 PM during weekdays. Participants can request one "demand charge credit" per year, calculated using the difference between the bill month’s kW demand and the kW demand from the same billing period the previous year.

In Missouri, regulators recently approved a default TOU rate with an unprecedented 5:1 peak to off-peak ratio for customers of the distribution utility Evergy. In Michigan, DTE Energy transitioned residential customers to a more modest default TOU rate in March 2023 (1.5:1 ratio), and Xcel Energy in Colorado was required to enact a similar reform in 2022. Table 4.1 shows all default TOU rates currently approved in the US. It is noteworthy that no state with retail choice (whereby consumers may select their electricity supplier for the generation portion of the bill) has yet implemented default TOU rates for network cost recovery. All examples except for Hawaii include network and supply costs bundled as a single per-kWh charge.

Table 4.1: Default TOU rates approved in the US[1]

State	**Utility**	**TOU Periods**	**Per-kWh charges**	**Status**
HI	Hawaiian Electric	Super off-peak: 9am - 5pm Off-peak: 9pm - 9am On-peak: 5pm - 9pm	Specific prices will be determined in future rate cases but must adhere to a 3:2:1 ratio for on-peak: off-peak: super off-peak. There will also be a grid access chart similar to capacity charges in Europe, but the amount is as yet unspecified.	Approved by PUC; set to take effect by July 1, 2024
CA	Several	Off-peak: 8pm - 5pm On-peak: 5pm - 8am	\$0.38/kWh off-peak \$0.42/kWh on-peak (Oct – May) \$0.51/kWh on-peak (Jun – Sep)	Active
CO	Xcel Energy	Off-peak: 7pm – 1pm Mid-peak: 1pm – 3pm On-peak: 3pm – 7pm	\$0.11/kWh off-peak \$0.19/kWh mid-peak \$0.27/kWh on-peak	Active
MO	Evergy	Off-peak: 8pm – 4pm On-peak: 4pm – 8pm	\$0.09/kWh off-peak \$0.38/kWh on-peak	Active
MI	DTE Energy	Off-peak: 7pm – 3pm On-peak: 3pm – 7pm	\$0.15/kWh off-peak \$0.16/kWh on-peak (Oct – May) \$0.21/kWh on-peak (Jun – Sep)	Active

These new rates are undoubtedly an improvement over flat volumetric tariffs. Under default TOU rates, consumers receive price signals that, as one rate reform advocate put it, dispel “the basic lie to retail consumers that every kilowatt-hour costs the same regardless of the time of day or the season of the year” [122]. And even though all rates allow customers

[1]For California, rates displayed are for PG&E’s default TOU plan.

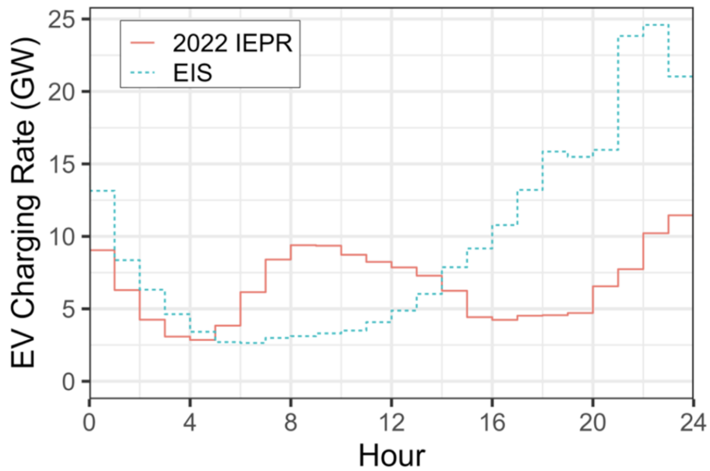


Figure 4.1: Illustration of rebound peak due to EV charging. The EIS curve depicts California EV charging demand in 2035 responding to a TOU rate with an off-peak period starting at 9:00 PM. (Source: Public Advocates Office [18])

to opt out and pay a flat volumetric charge, we can expect that only a small portion of customers will do so based on empirical evidence from opt-out TOU pilot programs [123] and utility resource planning [37].

However, by combining all costs into a single per-kWh charge, TOU rates create the potential for adverse impacts due to correlated demand responding in an automated manner in response to tariff price. This problem is particularly acute at the distribution level where there is relatively low diversity of customer loads compared to parts of the distribution network that host multiple housing types and customer classes (e.g., commercial and industrial). When a large population of EVs or heat pumps respond to a change in tariff price, it creates "rebound peaks" that may exceed existing peaks, shown in Figure 4.1. This phenomenon has been found empirically [124] and in simulation (e.g., [125], [126]) and limits the effectiveness of volumetric time-of-use rates at mitigating network impacts beyond low adoption levels.

4.1.2 Technology-Specific Tariffs

As an alternative or complement to default TOU rates, some US utilities have also begun to offer tariffs specifically tailored to EVs and CCHPs. Utilities and regulators recognize the unique operating characteristics of these devices, particularly their demand flexibility compared to other household appliances. These tariffs allow households to save money by shifting the timing of consumption to off-peak hours or allowing the utility to curtail consumption during critical periods.

Demand response programs that compensate customers (typically via a one-time or annual payment) in exchange for control of a smart thermostat have existed for many years. What is novel about some of these new programs is that they incorporate the expected savings into a discounted per-kWh charge. Households enrolling in electrification-specific tariffs are often not required to select a time-varying tariff for their remaining household demand. We review a selection of these dedicated electrification rates here, shown in Tables 4.2 and 4.3.

Table 4.2: Selection of EV-specific residential tariffs in the US

State	Utility	Details
MN	Xcel Energy	Unlimited charging between 9pm and 9am for a flat charge of $42.50/month
MA	Unitil	TOU rate for separately-metered EV charging:[2] On-peak (M-F 3pm - 8pm): $0.68/kWh Mid-peak (M-F 6am - 3pm): $0.45/kWh Off-peak (all other hours): $0.36/kWh
NJ	PSEG	Ex-post credit of $0.105/kWh for off-peak charging (between 9pm – 7am M-F), as measured by a compatible smart Level 2 charger
CA	Sonoma Clean Power	One-time $250 enrollment bonus plus $5/month in exchange for EV owners' authorization to curtail charging for up to 120 hours per year

A 2019 report by the Smart Electric Power Alliance estimated that across 20 utilities, 21% of eligible EV customers were enrolled on a specialized EV Rate [127]. The report demonstrated that participation increases significantly when the rate is marketed by utilities and connected to EV purchase incentives. The Vermont utility Green Mountain Power offers a free Level 2 charger with the purchase of any electric vehicle. Customers claiming this incentive are required to enroll on one of two EV rates: a TOU rate with an on-peak period between 1:00 PM – 9:00 PM on weekdays and a managed charging rate where the utility is allowed to curtail charging up to 5 times per month. Green Mountain Power reported that 80% of customers purchasing EVs claimed the free charger incentive and enrolled on one of the EV rates [128]. While Wong et al. [129] surveyed individuals and found that most people are in theory willing to participate in smart charging programs without incentives, Bailey et al. [130] use an actual field experiment to show that charging behavior reverts to uncontrolled (i.e., plug immediately upon returning home) when incentives are removed and only nudges provided.

For CCHPs, Central Maine Power (CMP) offers a seasonal heat pump rate with a significantly-reduced per-kWh rate during winter months, a higher per-kWh charge during summer months, and a slightly higher fixed charge all year round (shown in Table 4.3). Note that in contrast to the EV rates discussed, CMP's rate does not provide any incentive for shifting the timing of consumption; it is simply a discount for consumption during winter months for households who affirm that they have a heat pump (although no proof is required). One possible explanation for the lack of time-differentiation is that whereas some EV rates rely on metered data from the vehicle or charger that can be shared with the utility for billing purposes, there is no analogous source of data for heat pumps. The lack of integrated metering and Internet-connectivity is a barrier to offering time-differentiated heat pump rates without a secondary meter.

[2] These prices assume that the customer chooses Unitil for the supply portion of their bill.

Table 4.3: Central Maine Power's seasonal heat pump rate compared to its standard residential service rate

Tariff	**Customer Charge**	**Per-kWh Charge**
Seasonal Heat Pump Rate	\$37.71/mo	May – October: \$0.137508/kWh November – April: \$0.004317/kWh
Standard Residential Rate	\$21.55/mo	\$0.085717/kWh

4.2 Distribution Network Tariff Design in Europe

Since the advent of smart meters, Europe has been a pioneer in network tariff design. European regulators have implemented several innovative approaches for allocating network costs and sending efficient price signals. Until recently, these efforts had not been coordinated at an EU level but were instead spearheaded by individual member states.

Regulation (EU) 2019/943 mandates that EU member states implement cost-reflective distribution network tariffs, which implies that future network costs need to be reflected to the grid users through the tariff. The EU Agency for the Cooperation of Energy Regulators (ACER) reports that already 25 of the 27 assessed EU member States had some form of capacity distribution network charge in place (based on the maximum capacity in kW measured or kW contracted, with or without time-differentiation) [131].[3] As there are many nuances, it is hard to verify where households, connected to the lowest voltage level, are still facing more simplified distribution network charges. These simplified rates typically consist of a flat volumetric charge and a fixed charge. At the time of writing, based on ACER's analysis, we estimate that at least in one third of the member states households are facing some sort of capacity-based and/or TOU per-kWh network charges as the default [131]. We highlight four examples below.

In Spain, the distribution network tariff for residential consumers consists of both TOU per-kWh and TOU capacity components. The per-kWh component has 3 periods per day, with tariff levels ranging from 0.1 euro/kWh (off-peak) to 2.9 euro/kWh (on-peak). For the capacity component, consumers subscribe ex-ante to a desired level during two periods: on-peak and off-peak. If consumption exceeds the ex-ante level, power is temporarily disconnected at the meter, providing a real-time feedback signal to reduce simultaneous consumption.

In France, residential consumers have access to a regulated rate with a volumetric and capacity component. For the capacity component, consumers subscribe ex-ante up to a capacity level, and the price per kW goes down with more kWs contracted (i.e., declining block). For the per-kWh component, consumers can choose between a flat volumetric tariff, a simple two-part TOU tariff, and a dynamic tariff that resembles a critical peak rate where the utility announces one day prior whether it is a critical, peak, or off-peak day. During critical days, the price at all hours is significantly higher than peak and off-peak days, discouraging consumption at all hours equally.

[3] Capacity charges are described in detail in Section 5.2.

Italy's regulated distribution network tariff for residential consumers is similar to France's except it does not have a per-kWh component and the price per contracted kW does not change as the contracted amount grows.

Finally, the Flanders region in Belgium recently reformed its previously flat volumetric distribution network tariff. The new tariff consists of a small flat volumetric charge plus a capacity charge based on each consumer's 15-minute maximum demand in each month.

These four regulated distribution network tariffs in Europe provide inspiration for possible alternatives to the flat volumetric tariffs prevalent today in the US. While it is difficult to assess which of the European designs performs the best - and each country faces a unique set of challenges related to its clean energy transition - it is telling that all tariffs include a deterrent to maximum power consumption in the form of a capacity charge (either ex-ante or ex-post).

Among other European countries, there has been interest in reforming distribution network tariffs to comply with the new EU regulation and improve efficient utilization of the existing network. In Norway, while network tariffs today are predominantly volumetric, the energy ministry proposed shifting to a three-part tariff consisting of time-differentiated per-kWh charge, a capacity charge, and a fixed charge [132].

In the UK, OFGEM (the UK energy regulatory agency) initiated a review of network tariffs in 2018 via a Significant Code Review process. Network access charges were modified to only recover "shallow costs" directly related to interconnection, and OFGEM has an ongoing effort to reform forward-looking charges since 2022 [133].

Looking beyond the distribution network component of the bill (which is typically determined by national regulators) Europe also has an advanced electricity retail supply industry. Suppliers have created innovative offerings that help customers reduce costs by adjusting the timing of consumption or allowing for direct load control, which also serve as inspiration for US tariff reform efforts (though outside the scope of this thesis). For example, in the UK, the retailer Octopus Energy offers a tariff where the price of electricity for EV charging is heavily discounted for four overnight hours. In Spain, Iberdrola's retail arm allows consumers to select their off-peak energy tariff hours based on their household schedules.

In this chapter, we reviewed recent tariff reform efforts in the US, including both whole-home default TOU and device-specific offerings. We also explored popular distribution network tariff designs in Europe that have been effective at reducing local peak demand and allowing grid users to reduce their costs by changing the timing of consumption. While most European countries use some form of incentive regulation for electric distribution companies, there is no reason why US regulators could not impose the same types of tariffs prevalent in European countries. In the next chapter, we introduce the methodology for our case studies in which we test tariff designs widely implemented in Europe.

Chapter 5

Methodology: Simulating Residential Electrification Under Distribution Network Tariff Alternatives

The grid impacts of electrification have been modeled extensively, but the interaction between electrification and distribution network tariff design is only a nascent field, as discussed in Chapter 3. In this thesis, we develop a modeling framework that allows us to understand how distribution network tariff design impacts network investment needs in the face of high electrification. This in turn allows us to assess the evolving economics of electrification for individual households and distributional impacts on different customer groups.

In this chapter, we describe the modeling framework and case study formulation, including key assumptions and performance metrics. We adhere to several principles in our analytical approach:

1. Leverage open-source data to the greatest extent possible
2. Isolate the impacts of tariff design (in contrast to other dynamics like consumer technology adoption)
3. Choose representative geographies
4. When making assumptions, try to approximate actual end-use behavior based on empirical data

Our approach combines open-source data and a previously-developed building optimization model with a novel rate design "engine" to translate network investments into long-term cost impacts, much in the same way that a rate case would allocate costs to consumers. The core research contribution is the creation of a tool that allows utilities and regulators to understand the long-term impacts of tariff design on customer costs at different points in the electrification adoption curve. In contrast, most research on the impacts of electrification look at a single point in time (e.g., the peak day or peak week) or focuses only on the costs for electrified households. While any tariff reform will create winners and losers in the short-term, it is important to consider how new proposed rates will impact *future* investment needs, which directly influence costs paid by grid users. Through this analysis, we can better understand under which scenarios electrification would apply downward or upward rate pressure, tradeoffs in tariff design (e.g. simplicity vs efficiency), and how to better ensure beneficial outcomes for all customer groups.

The modeling process consists of several components, listed here, and described in greater detail in the subsections below:

1. Select data sources
2. Define distribution network tariff options
3. Select geography, choose representative network investment cases, and configure distribution network model
4. Simulate residential electricity consumption in response to tariff design
5. Calculate network investments and changes to tariff prices

Using these steps, we conduct two cases studies:

1. Price-responsive EV charging in a warm-climate geography with a detailed network model (Greensboro)
2. Price-responsive EV and CCHP operation in a cold-climate geography with a simplified network model (Massachusetts)

The two case studies share many features. They differ in geography, type of end-use consumption that is price-responsive, type of electrification, and tariff scenarios tested.

5.1 Data Sources

5.1.1 Household Energy Consumption Profiles

We obtain residential energy consumption time series data from the ResStock Database created by the National Renewable Energy Laboratory. ResStock provides synthetic annual hourly electricity and fuel consumption for a collection of simulated residential building archetypes, calibrated against actual building performance [134]. Consumption is segmented by household appliance end use (e.g., lighting, clothes washer, heating, etc). We choose diverse samples of buildings using the *weight* key, which indicates how representative each building archetype is of the actual housing stock in a census region. We consider only single family detached houses, using measure package zero (baseline). We remove houses with solar photovoltaic and battery storage because total consumption reflects the net consumption inclusive of self-consumed and exported solar generation. We use load profiles for the actual meteorological year 2018. One limitation of our study is that as electrification proceeds, we do not use future forecasted temperature data.

5.1.2 Vehicle Driving Profiles

We use the National Household Travel Survey (NHTS) to generate vehicle driving profiles. NHTS is conducted every 5 years by the US Federal Highway Administration and asks respondents to log all trips taken within one 24-hour period, starting at 4:00 AM local time and ending at 3:59 AM local time the next day [135]. For each trip, the respondent includes the trip purpose, arrival and departure times, number of miles traveled, and start and end locations. For households with multiple vehicles, each vehicle is tracked separately. While there are longitudinal datasets on driving patterns, these are limited to small geographies. Using the NHTS dataset, which includes all 50 states, allows us to extend our approach to the entire US.

Starting with the raw NHTS trip data, we obtain, for each vehicle, a parameter profile that contains the earliest home departure hour, the latest home arrival hour, and the total number of miles driven in the 24-hour period. These parameters signify when the vehicle is expected to be plugged in at home and the amount of electricity required to restore the battery's state of charge. The NHTS data includes trip weights to indicate how representative each trip is of all trips in a region, which we use for sampling purposes.

Because the NHTS survey is not longitudinal (i.e., each survey response covers only a 24-hour period of travel behavior), we use the following procedure to translate the survey responses to annual driving profiles. We require an annual profile because we are interested in not only peak demand during certain representative days but also annual cost impacts. While ResStock is not linked to NHTS data explicitly, both datasets include household demographic data, including income level and number of occupants, allowing us to match vehicles with households that have similar features.

1. For each ResStock household, we filter the NHTS data for vehicles associated with households of the same income level and number of occupants.

2. Using the NHTS trip weights, we randomly select one weekend and one weekday parameter profile (containing the departure hour, arrival hour, and miles driven) to associate with the household. These profiles provide the inputs to convert from survey responses to pseudo-random travel profiles.

3. For each house, we create weekend and weekday normal distributions centered at the actual number of miles driven with a standard deviation equal to 10% of the number of miles driven. We create discrete distributions for the weekend and weekday arrival and departure hours, as shown in Figure 5.1.

4. For each day of the year, we sample a departure and arrival hours from the discrete distribution and sample the daily mileage from the normal distribution (weekend or weekday).

5. We convert daily miles driven to electricity consumption using the regression computed by Yuksel and Michalek [82] in which battery efficiency depends on outdoor air temperature. We use the average temperature during hours that the vehicle is not at home on the given travel day. The difference in energy efficiency throughout the year

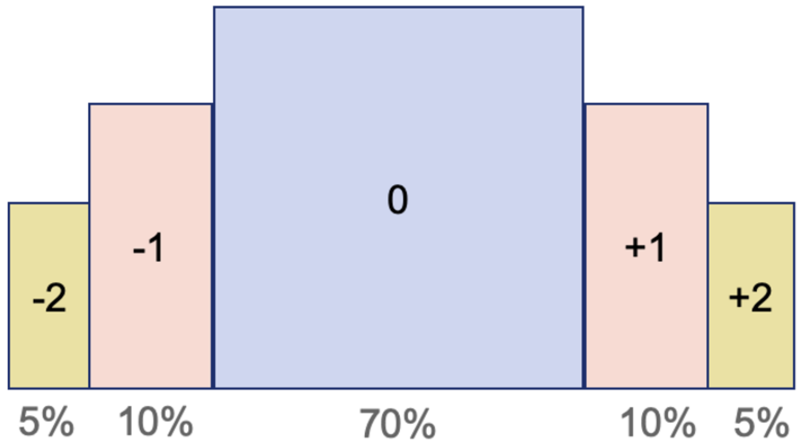


Figure 5.1: Discrete distribution used to select departure and arrival hour for driving profiles each day. The numbers in the boxes represent the offset (in hours) from the hour in the NHTS parameter profile. The percentages below reflect the probability of drawing from each box.

is due to both the temperature impacts on battery chemistry and cabin heating and air conditioning.

After this procedure, each household has a unique and uncorrelated annual vehicle usage profile that indicates when the vehicle is home versus away, and the daily electricity consumption due to driving. We use this profile to assign an EV battery capacity. The available capacities, based on common EVs available for purchase today, are 12, 40, 60, 90, or 120 kWh (the 12 kWh represents a plug-in hybrid electric vehicle). We select the minimum capacity that fulfills the vehicle's maximum daily electricity consumption, plus a 20% buffer. This assignment captures the expectation that households that routinely drive short distances are more likely to buy EVs with smaller batteries, which have lower associated capital costs. For any house where meeting the annual charging need is infeasible even with the maximum available battery size (i.e., the car is not plugged in long enough at home to avoid depleting the battery), we assume that house does not purchase an EV. This design choice aligns with the approach by Wei et al. [136].

5.1.3 Distribution Network Topology

For the Greensboro case study, we use synthetic distribution network topologies to study the impacts of electrification. In the absence of real network data from utilities (which typically cannot be shared due to security and privacy concerns), one widely used open-source distribution grid dataset is SMART-DS, developed by the National Renewable Energy Laboratory jointly with MIT and Comillas Pontifical University in Madrid, Spain. [1] SMART-DS builds synthetic grid topologies using the Reference Network Model [137], including all electrical

[1] https://www.nrel.gov/grid/smart-ds.html

components (e.g., lines, substations, capacitors, regulators, fuses, etc). These components connect to buildings modeled in ResStock and ComStock (for commercial buildings). The dataset is structured as nested directories to reflect the distribution grid's hierarchy, from the sub-transmission network down to distribution feeders. SMART-DS can be used to run power flows (using either CYME or OpenDSS software) for studying network behavior under different technology adoption scenarios. The authors performed extensive validation against real-world distribution feeders in the US. Integration with ResStock makes SMART-DS an ideal tool for studying where thermal and voltage violations appear at higher electrification levels. SMART-DS has been developed for 3 US cities (Austin, TX, Greensboro, NC, and San Francisco, CA), in addition to the entire state of Texas as part of the Texas Combined Transmission-Distribution Test Case developed at Texas A&M University in joint partnership with the aforementioned institutions.

5.2 Tariff Price Calculation

We test variations on three standard formats of distribution network tariff design: fixed, per-kWh, and capacity (based on per-kW demand). These designs are not mutually exclusive; they can be combined to create hybrid tariffs that balance different policy objectives. Table 5.1 shows the key details of each tariff type, along with illustrative prices.

Below, we describe how tariff prices are calculated in our case studies. We assume that energy and distribution network tariffs are designed separately (even if the utility is vertically integrated). We pair the distribution network tariffs under consideration with two types of energy tariffs: flat per-kWh and time-of-use per-kWh. The energy tariff prices are exogenous to the model. We consider only whole-home, technology-agnostic tariffs that have been implemented widely outside the US, with consumption measured using a single utility meter. In the equation descriptions below, "revenue requirement allocation" refers to the portion of the revenue requirement allocated to that charge type (i.e., fixed, per-kWh, or capacity).

5.2.1 Fixed Charges

The fixed tariff is simply the revenue requirement allocation divided by the number of grid users.

5.2.2 Per-kWh Charges

The 1-part per-kWh tariff is the revenue requirement allocation divided by aggregate annual consumption. The 2-part TOU per-kWh tariff (we do not consider 3- or 4-part TOU) is calculated using Equation 5.1. The on-peak price is set at two times the off-peak price, which is common among US utilities [34].

$$Rate_{off-peak} = RevReq_{per-kWh}/(Cons_{off-peak} + 2 * Cons_{on-peak}) \quad (5.1)$$

$$Rate_{on-peak} = 2 * Rate_{off-peak} \quad (5.2)$$

Table 5.1: Summary of distribution network tariff types with illustrative prices

Tariff Type	Variant	Periods	Illustrative Price	Description
Fixed	-	-	\$1000/year	Each consumer pays a fixed amount regardless of consumption. May be the same for all customers or differentiated based on, e.g., income
Per-kWh	Non-Time-differentiated (Flat)	1	\$0.11/kWh all hours	Per-kWh charge with no time variation
	Time-differentiated (TOU)	2+	\$0.08/kWh off-peak \$0.16/kWh on-peak	Per-kWh charge where total cost is the consumption in each period multiplied by the per-kWh price in that period. The on-peak charge is typically set at least two times the off-peak charge
Capacity	Ex-post measured (demand charge)	1+	\$170/kW-year	Assessed based on the consumer's maximum measured demand during each billed period
	Ex-ante contracted (subscription charge)	1+	\$150/kW-year	Consumer subscribes in advance to maximum threshold that cannot be exceeded

where $Cons_p$ is the aggregated off-peak consumption during period p (on-peak or off-peak), $Rate_p$ is the per-kWh charge (\$/kWh) during period p, and $RevReq_{per-kWh}$ is the revenue requirement allocation.

5.2.3 Capacity Charges

We consider two types of capacity (per-kW) tariffs: ex-post measured (demand) and ex-ante contracted (subscription).

Ex-Post Measured (Demand Charges)

An ex-post measured capacity charge (also called a demand charge) involves measuring the maximum demand during the billing period. In practice, it is calculated either by: 1) averaging several instantaneous demand readings during each hour and taking the maximum of those averages; or 2) taking the maximum instantaneous reading. In our case studies, this implementation detail is not relevant because we work with hourly consumption data.

We test three different demand charges in our case studies: 1-part, 4-part (with seasonality), and monthly (i.e., 12-part). The 1-part demand charge (DC) is computed by dividing the revenue requirement allocation by the sum of each household's maximum annual demand.

$$DC = RevReq_{capacity} / \left(\sum_{j}^{n} max_{i\epsilon\{1,\dots,8760\}} \left(demand_{j,i} \right) \right) \tag{5.3}$$

where n is the total number of households and $demand_{j,i}$ is household j's total demand in hour i. The resulting 1-part demand charge (DC) has the units of $/kW; each customer's demand-based network cost is that value multiplied by their maximum demand across all hours of the year.

We elaborate on the simple 1-part demand charge by adding time differentiation, both intraday (on-peak and off-peak) and seasonal (winter and summer). The hours and months contained in each period are unique to each case study, explained in Section 5.4. Under the 4-part demand charge, households pay a separate charge for their maximum demand in each of the following periods:

- Winter On-peak (WN)
- Winter Off-peak (WF)
- Summer On-peak (SN)
- Summer Off-peak (SF)

To calculate the price for each period, we use a similar methodology as the 1-part demand charge but apportion equal parts of the revenue requirement allocation to each seasonal period (i.e., demand charges for the winter period collect one half of the revenue requirement allocation and demand charges for the summer period collect the other half). Within each season, we set the on-peak charge to be two times the off-peak charge.

$$DC_{WF} = \frac{1}{2} RevReq_{capacity} / \left(\sum_{j}^{n} max_{i\epsilon\{WF\}} \left(demand_{j,i} \right) + 2 \sum_{j}^{n} max_{i\epsilon\{WN\}} \left(demand_{j,i} \right) \right) \tag{5.4}$$

$$DC_{SF} = \frac{1}{2} RevReq_{capacity} / \left(\sum_{j}^{n} max_{i\epsilon\{SF\}} \left(demand_{j,i} \right) + 2 \sum_{j}^{n} max_{i\epsilon\{SN\}} \left(demand_{j,i} \right) \right) \tag{5.5}$$

$$DC_{WN} = 2 * DC_{WF} \tag{5.6}$$

$$DC_{SN} = 2 * DC_{SF} \tag{5.7}$$

where $i\epsilon\{WF\}$ indicates hours i contained in the set of winter off-peak hours $\{WF\}$ and defined similarly for the other periods.

We design the monthly demand charge to be equal for all months of the year:

$$DC_{monthly} = RevReq_{capacity} / \left(\sum_{m=1}^{12} \sum_{j}^{n} max_{i\epsilon\{m\}} \left(demand_{j,i} \right) \right) \tag{5.8}$$

where $i\epsilon\{m\}$ indicates hours i contained in month m.

Note that while demand charges are typically implemented as monthly charges, this is done to align with traditional utility billing cycles. The drivers of network costs are not bound by calendar months.

Ex-Ante Contracted (Subscription Charges)

Unlike a demand charge, in a subscription charge, the consumer selects a capacity level in advance. This works similarly to an Internet plan where customers select their bandwidth from a menu of options. In some implementations, if the customer exceeds the subscribed level, their power is cut off temporarily; in other cases, a penalty charge is imposed. Customers can determine their contracted (i.e., subscribed) level by looking back at their historical consumption.

To calculate the subscription tariff charges, we run the optimization under the demand charge case, which provides the maximum demand in each period. We calculate the subscription level as the maximum usage in each period *plus a 1 kW buffer*, rounded to the nearest whole kW value. This is meant to mirror the exercise a household would do to determine its subscription level (albeit with historical consumption data rather than perfect foresight), with the buffer representing a small amount of aversion to exceeding the historical peak values and incurring a penalty or lost load. After the subscription level for the different periods is determined, we re-run the optimization but with a hard physical cap equal to the assigned subscription value per time period. The subscription charge (SC) in each seasonal period p is calculated in Equation 5.9 (with on-peak subscription charge set equal to two times the off-peak subscription charge in each period, as with demand charges and per-kWh charges):

$$SC_p = K_p * RevReq_{capacity} / \left(\sum_{j}^{n} subscription_{j,p,off-peak} + 2 \sum_{j}^{n} subscription_{j,p,on-peak} \right) \tag{5.9}$$

where K is the cost allocation factor for period p (e.g., 1/2) and $subscription_{j,p,off-peak}$ is the pre-subscribed capacity level for household j in seasonal period p during off-peak hours (and defined similarly for on-peak hours). Because it is not possible for a household to exceed its pre-subscribed value in our model, we do not define a penalty cost function.

In our case studies, we envision the network tariffs as mandatory whereby grid users cannot opt out and select other tariff designs. Note that consumers could still choose their electricity supply tariff, either from the local distribution utility (in vertically integrated states) or a retail supplier (in states with retail choice). In our description of the case studies below, we provide the full set of tariffs considered in each case.

5.3 Analytical Methods

5.3.1 Optimization Formulations

We simulate each household's electricity consumption using a mixed integer linear program. The objective is to minimize the annual electricity cost, inclusive of network and energy costs.[2] EV chargers can vary kW demand while cars are plugged in. We assume that households respond rationally to price signals (with perfect foresight) and that appliance loads unrelated to EV charging and CCHP systems are inelastic (i.e., not price responsive). While there is ample evidence that residential consumers will make behavioral changes in response to electricity tariffs (e.g., [102]), these are relatively small compared to the flexible loads we consider in this thesis. In this way, our analysis envisions a "lower bound" scenario, with no change in consumer behavior outside of electrification-driven load.

In our first case study, we use a simplified optimization model where only EV charging is price-responsive. The model is implemented in the Python programming language using the Gurobi solver. The objective function for each household is defined as:

$$min\sum_{i}^{8760}\{c_i * (N_i + E_i)\} + \sum_{p}\{max_i\left((c_i + A_i) * B_{i,p}\right) * DC_p\} + \sum_{i}^{8760}(maxsoc - soc_i) * 1e^{-4} \tag{5.10}$$

where:

- c_i is the charging value for each hour i (the decision variable)
- A_i is the non-EV load for each hour i
- N_i is the per-kWh network charge (in \$/kWh) for each hour i
- E_i is the per-kWh energy charge (in \$/kWh) for each hour i
- DC_p is the demand charge for each demand period p
- $B_{i,p}$ is a binary variable that indicates whether an hour i is part of a demand period p
- $maxsoc$ is the battery's capacity
- soc_i is the energy in the EV battery for each hour i

The last part of the objective function ensures that EVs charge as early as possible such that the cost of charging does not increase. This is achieved by assessing a small penalty function (several orders of magnitude smaller than the per-kWh or capacity charges) for any hour when the battery is not fully charged. This reflects the empirically-observed behavior that EV owners overwhelmingly schedule charging to happen at the beginning of the low-price off-peak period [124], [128].

The model is subject to the following constraints:

$$minsoc \leq soc_i \leq maxsoc \tag{5.11}$$

$$0 \leq c_i \leq VS_i * 7.2 \tag{5.12}$$

$$soc_i = soc_{i-1} + (c_i - D_i) \tag{5.13}$$

$$soc_0 = maxsoc \tag{5.14}$$

$$soc_{8760} = minsoc \tag{5.15}$$

[2] For simplicity, we omit customer charges and policy-related charges. Assuming these would be continue to be collected via flat volumetric rates, this omission has no impact on optimal load profiles.

The first constraint ensures that the battery's state of charge never goes above the battery's capacity or below a minimum state of charge, set at 20% of the capacity. The second constraint limits EV charging to the power of a standard Level 2 residential charger, prohibits negative charging,[3] and guarantees that the car can only charge when the vehicle is at home; VS_i is a binary status variable equal to 1 when the vehicle is at home and equal to 0 when the vehicle is away from home. The third constraint specifies that at each hour, the state of charge of the battery is equal to its state of charge in the previous time step plus the net charging value; D_i is the amount of energy drawn from the battery, set equal to the full day's electricity consumption in the hour the vehicle departs home (in order to ensure that the vehicle is sufficiently charged before departure). Finally, the fourth and fifth constraints set the vehicle's initial and final battery states of charge. For subscription charge scenarios, the objective function omits the middle summation of Equation 5.10; the ex-ante subscription level becomes a constraint.

Our second case study uses a model developed by several researchers at the MIT Energy Initiative [138], [139]: Distributed Energy Consumption in Actively Responsive Buildings (DECARB). The DECARB model is a mixed integer linear program that minimizes a building's total energy costs. DECARB is written in the Julia programming language and can be configured to allow the building owner to invest in new technology, for example solar photovoltaic and battery storage. However, in this thesis, we define technology adoption exogenously and specify each household's appliances ex-ante based on the level of electrification. The key inputs to DECARB are building metadata obtained from ResStock (including square footage, thermal properties of the walls and floors, and time series consumption for lights and appliances), outdoor air temperature, a catalog of installed equipment, price data, and thermal comfort bands.

DECARB minimizes cost by shifting the timing of electricity consumption within comfort limits. For HVAC systems, this might mean, e.g., pre-heating or pre-cooling the building during low-price hours and "riding through" high-price hours as the temperature approaches the comfort limit. As part of this thesis, we developed a new EV module for DECARB to allow EV charging to be co-optimized alongside other household demands. This is particularly important for capacity-based tariffs, where optimal charging behavior depends on the household's aggregate consumption.

5.3.2 Feedback Loop for Recovering Network Investments and Recomputing Charges

In this thesis, we employ an iterative approach to study the interaction between distribution network tariff design, network investment, and resulting cost impacts on different customer groups. The approach is meant to roughly approximate how a regulator would set rates based on forward-looking demand forecasts. We define electrification exogenously; the order in which houses are selected for electrification is random, cumulative, and proceeds in 5% increments. In other words, all EV/CCHP households in the 5% electrification scenario remain EV/CCHP households in the 10% scenario.

[3]While "vehicle-to-grid" (V2G) holds promise, the technology is immature and it remains to be seen whether automakers will allow it under battery warranty programs.

At each step in the electrification adoption curve, we simulate (in a bottom-up fashion) price-responsive household electricity consumption as described above and calculate demand-driven network investments. [4] We assume network investments are linearly correlated with aggregate annual peak demand, a limitation we discuss in Section 7.3. Network investments add to the revenue requirement, the amount recovered from consumers via the network tariff. For simplicity, we assume that there is no return on investment. Equation 5.16 describes the linear relationship between the aggregate peak demand and revenue requirement.

$$RevReq = BNC + LRMC * (SP_t - SP_0) \tag{5.16}$$

$LRMC$ is the long-run marginal cost of expanding the network. We consider two cases: low-cost network expansion (\$100/kW) and high-cost network expansion (\$500/kW).[5] These values are obtained from Lee [139], which takes an average of marginal distribution cost studies in various parts of the US. We treat these values as representative endpoints of a cost spectrum, rather than exact predictions. The baseline network cost (BNC) is defined as the product of the annual aggregated consumption at 0% EV/CCHP adoption times the current flat per-kWh network charge for the distribution utility in each region. We assume that all distribution network costs are allocated to the existing flat per-kWh network charge (i.e., no distribution-related costs are recovered in other line items). SP_t is the aggregate system peak for the electrification level t and SP_0 is the aggregate system peak at 0% electrification. The tariff price levels are then updated (via the equations in the Section 5.2) to collect the new revenue requirement.

For each incremental level of electrification, we first compute a naive solution where the tariff price levels are set to collect the revenue requirement at 0% EV adoption. Using the optimized load profiles from the naive run, we obtain the annual peak demand and new revenue requirement (from 5.16) We then recalculate the tariff prices to recover the new revenue requirement and re-run the optimization. Equilibrium is reached when the household responses do not deviate from the previous iteration and the full revenue requirement is collected. Figure 5.2 provides a visual overview of our methodology.

For all case studies, tariffs are recomputed only at discrete time steps (5% adoption intervals). This is meant to approximate the "regulatory lag" that describes the interval between utility rate cases. Unlike some studies(e.g., [116], [117]), we do not conduct a bi-level optimization where the utility minimizes its total costs while consumers minimize their bills. In the US, distribution utilities have no explicit financial incentive to minimize costs.

[4] While we consider distribution at only one layer, in reality it is a cascade of layers [111], with impacts aggregating up, correcting for increasing diversity through the entire distribution hierarchy [16]. The problem of correlated EV and CCHP operation is especially apparent at the lowest distribution layers, especially residential feeders with low load diversity. If we considered more layers, the impact of correlated consumption would be less pronounced; the higher you aggregate up the more you can leverage load diversity. In this way, our approach considers the "weakest link" of the cascade.

[5] Both values are annualized over the lifetime of the equipment entered into service.

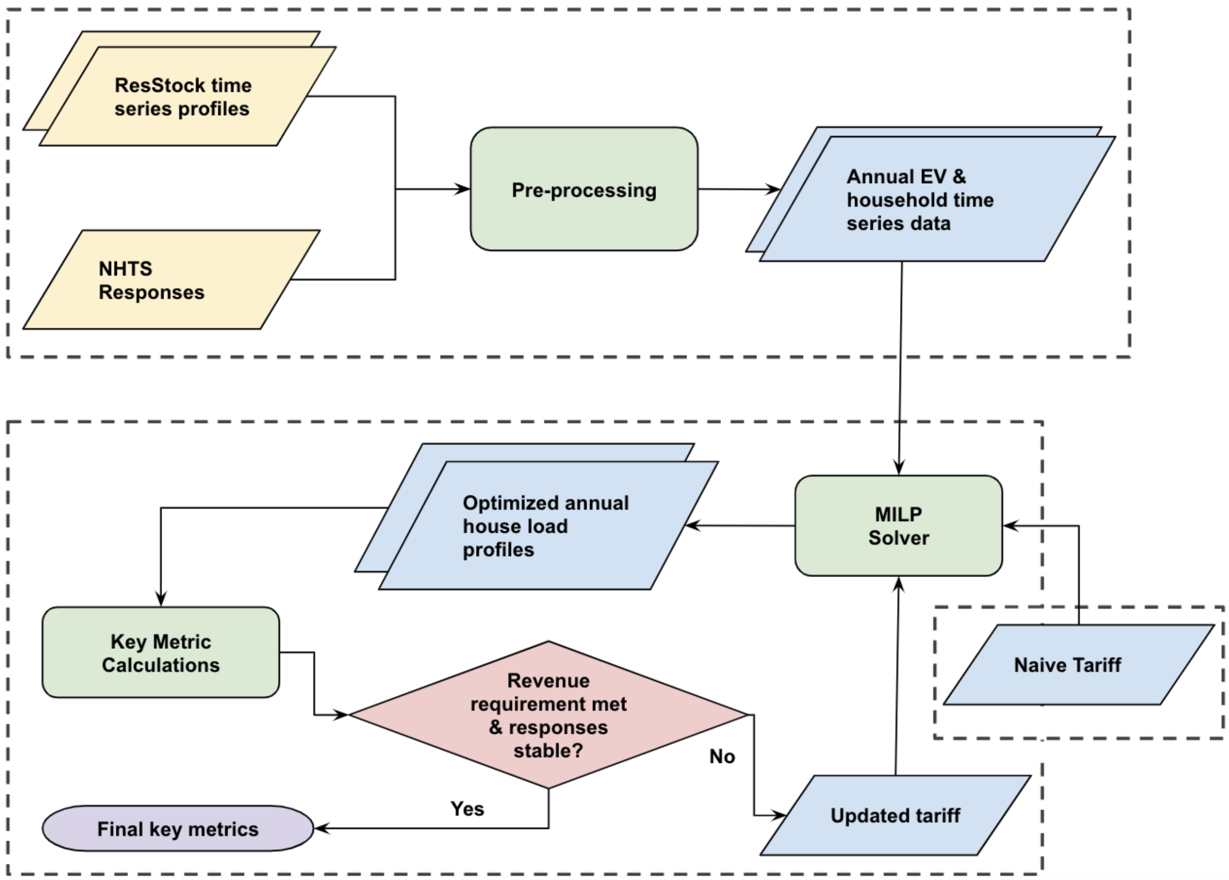


Figure 5.2: Illustrative flowchart of methodology; ResStock is a database of synthetic hourly load profiles for representative US homes. NHTS is the National Household Travel Survey, in which respondents log their travel behavior.

5.4 Case Study Outlines

In this section we provide key assumptions, design decisions, and tariffs considered for our two case studies. The following design details are the same in both case studies:

- For the TOU energy tariff, we set the on- and off-peak prices to be revenue neutral with a flat per-kWh tariff at 0% EV/CCHP adoption. The on-peak price is two times the off-peak price (as in Equation 5.1). The TOU energy tariff prices remain the same at all levels of EV adoption (a limitation we discuss in Section 7.3).
- We use the same on and off peak hours for both network and energy tariffs.
- We assume electrical panel capacities are sufficiently large to accommodate new demand from EVs and CCHPs.

5.4.1 Greensboro (North Carolina): Price-Responsive EV Charging in a Warm-Climate Geography with a Detailed Network Model

For this case study, we select one distribution feeder from the Greensboro, NC Smart-DS dataset (feeder rhs2_1247–rdt1262). The feeder has 376 buildings, 339 of which are residential. We omit the non-residential buildings from this analysis. The feeder has an annual peak demand of 1.6 MW. We take the ResStock time series profiles assigned to each building as the base load and, at 5% adoption increments, assign to each household an EV (from North Carolina's NHTS responses) whose driving profile is calculated using the approach outlined in Section 5.1.2. EV charging is optimized under the network and energy tariffs listed in Table 5.2.[6] All simulations were run on a 2.3 GHz Dual-Core Intel Core i5 laptop computer.

The Smart-DS dataset does not provide metadata or thermal time series data for the ResStock profiles assigned to each building. Because we do not have information on existing heating equipment, square footage, or total heating load, it is not possible to "convert" each building to electric heating. However, North Carolina has a warm climate and many buildings already heat with electricity [140], [8]. We believe it is reasonable to assume that the feeder will not see a significant increase in demand due to CCHP adoption, making EVs the dominant source of new residential load. One area for future work is to match the ResStock timeseries profiles in Smart-DS with timeseries data for buildings in public ResStock releases for which metadata is available; this would allow consideration of both heating and transportation electrification on realistic network topologies.

To set the initial tariff prices, we use Duke Energy's standard residential tariff (RS), which has a customer charge of \$14.00 per month and a per-kWh charge of \$0.114311/kWh. Duke Energy does not differentiate between network and energy charges on the bill; we assume that 50% of the per-kWh charge recovers network costs. We use Duke's residential TOU (RT) tariff to set the on- and off-peak hours. On-peak includes weekdays 6:00 AM - 9:00 AM and 4:00 PM - 9:00 PM whereas all other hours as off-peak. For tariffs with

[6] Abbreviations in Tables 5.2 and 5.3: DC = Demand Charge, SC = Subscription Charge, WN = Winter On-Peak, WF = Winter Off-Peak, SN = Summer On-Peak, SF = Summer Off-Peak

seasonal periods, we use the RT tariff's seasonal delineations: May - September (Summer) and October - April (Winter).

We consider two types of per-kWh energy tariff (flat and TOU) and six types of distribution network tariff (fixed, flat per-kWh, TOU per-kWh, 1-part demand charge, 4-part demand charge, and 4-part subscription charge). For the fixed and capacity tariffs, we collect one half of the total network revenue requirement via a flat per-kWh charge and the other half via the fixed or capacity charge. This design decision is meant to temper extreme distributional impacts and ease the transition away from the status quo.

Table 5.2 shows the combinations of energy and distribution network tariffs considered in the Greensboro case study. We omit the *eflat_ntou* and *etou_nflat* tariffs because they are duplicative of results from other scenarios.

5.4.2 Massachusetts: Price-Responsive EV and CCHP Operation in a Cold-Climate Geography with a Simplified Network Model

For this case study, we select 300 ResStock profiles from suburban counties in the Greater Boston Area, where heating is dominated by natural gas and both EV and CCHP penetrations are low today. In this case study, we have metadata for all households, which we use to filter for ResStock house archetypes with natural gas heating and floor area between 1500 - 2500 square feet. We select driving profiles for households by matching occupant and income information between the ResStock archetype and NHTS survey responses filtered for Massachusetts. For households selected for electrification at each step in the adoption curve, we assign *both* an EV and a CCHP system, then use DECARB to co-optimize their operation.[7] The CCHP system is an air source ductless heat pump sized to meet the full annual heating load without backup heating. This design choice adheres to a Massachusetts whole-home CCHP rebate program, which requires participants to remove their backup heating system in order to claim the full rebate [143]. The thermal comfort band (i.e., setback temperature range) is 19C - 24C, regardless of occupancy.[8] We use the same linear coefficient of performance curve for CCHPs as in Khorramfar et al. [72]. We allow the heat pump to be used for cooling regardless of whether the ResStock archetype had existing air conditioning, which reflects behavior from actual heat pump customers [144]. We assume that the 300 households are electrically connected in the same neighborhood and distribution grid. The annual baseline peak demand is 729 kW.

Unlike the Greensboro case study, in Massachusetts network and energy charges are separated on the bill (shown in Figure 1.2). We use Eversource's network tariff price ($0.13486/kWh) and the author's energy supply charge ($0.1481/kWh) as of April 1, 2024. Eversource does not currently offer TOU rates for residential customers. We set the on- and off-peak hours to be equal to the Greensboro case, which aligns well with the highest demand hours for all households in the sample. For tariffs with seasonal periods, we define Winter as November - March and Summer as April - October.

[7] While it is unlikely that heat pump adoption would overlap perfectly with EV adoption [19], it is reasonable to assume some overlap [141], [142].

[8] A "smart" thermostat could learn occupancy patterns and adjust this setback range, but we do not model that possibility here.

Due to the computational demands of simulating each building's thermal performance, we tested five tariff scenarios in the Massachusetts case study, shown in Table 5.3. For the capacity distribution network tariff scenarios, we collect one third of the total network revenue requirement via a flat per-kWh charge and the other two thirds via the capacity charge.

All simulations were run using the Gurobi solver on the MIT SuperCloud [145].[9] DECARB does not have support for subscription charges so we consider only demand charges for the capacity-based alternatives. For the 4-part Demand Charge, rather than a 2:1 on-peak:off-peak ratio within each seasonal period, we set a price of $0/kW during the off-peak periods and recover each season's revenue requirement allocation entirely through the on-peak demand charge. This is intended to encourage pre-heating and pre-cooling. For the monthly demand charge, we set the price to be the same amount in each month, which reflects how demand charges are typically implemented in the US for commercial customers.

5.5 Key Metrics

We assess each tariff design based on three metrics: aggregate peak demand (which is linearly correlated with total network cost), levelized operating cost of new equipment for electrified households, and network cost impacts for non-electrified households who do not change their consumption patterns. Levelized operating costs of new equipment directly affect the total cost of ownership, which determines whether and how much customers will save compared to internal combustion engine vehicles and fossil-fueled heating systems. Non-electrified household costs capture the distributional impacts of each tariff and indicate whether each will be acceptable from an equity perspective, especially when considering that EV adoption until now has correlated strongly with income [146]. Ideally, only electrified households should pay the incremental network costs due to increased adoption (since non-electrified household loads remain the same in our model). Yet in practice and in our simulations, distribution network tariffs include not only forward-looking costs but also sunk costs of prior investments. The implications of this design choice are discussed further in Chapters 6 and 7.

We compute the following statistics for each tariff at each 5% increment in the electrification adoption curve. We provide a brief description and equation for each.

Annual Peak: the maximum hourly demand for the aggregated load over all consumers, measured in kW:

$$max_{i\epsilon\{1,\ldots,8760\}} AggDemand_i \tag{5.17}$$

where $AggDemand_i$ is the sum of all individual demands in hour i.

Levelized EV/CCHP operating cost: the average cost paid by EV/CCHP households for charging/heat pump operation, calculated as the total incremental costs divided by total

[9] We acknowledge the MIT SuperCloud and Lincoln Laboratory Supercomputing Center for providing HPC resources that have contributed to the research results reported within this thesis.

incremental consumption, measured in \$/kWh:

$$\sum_{j}^{n} E_j(Cost_{E,j} - Cost_{B,j}) / \sum_{j}^{n} E_j(Cons_{E,j} - Cons_{B,j}) \tag{5.18}$$

where E_j is 1 if the household is electrified and 0 otherwise, $Cost_{E,j}$ and $Cons_{E,j}$ are the total post-electrification cost and consumption, respectively, and $Cost_{B,j}$ and $Cons_{B,j}$ are the total pre-electrification (i.e., baseline) cost and consumption, respectively.

Distributional impact: the average change in network cost ($NWCost$) paid by non-electrified households compared to a scenario of flat per-kWh network and flat per-kWh energy tariffs at 0% electrification, i.e. the "status quo" (SQ), measured in percentage change:

$$\left(\sum_{j}^{n} (1 - E_j)(NWCost_j - NWCost_{SQ,j}) / NWCost_{SQ,j} \right) / \sum_{j}^{n} (1 - E_j) \tag{5.19}$$

Under the assumptions outlined in this chapter, we isolate the impact of distribution network tariff design (and the interaction between energy and distribution network tariffs) on electrification adoption economics and distributional effects. These help determine which tariff designs offer the best chance of achieving beneficial electrification.

Table 5.2: Tariffs tested in the Greensboro case study

Alias	**Energy Tariff**	**Distribution Network Tariff at 0% EV**	**Relevant Periods**
eflat_nfixed	$0.06/kWh	Fixed: $34/month Per-kWh: $.03/kWh	N/a
etou_nfixed	On-peak: $0.09/kWh Off-peak: $0.04/kWh	Fixed: $34/month Per-kWh: $.03/kWh	On-peak: M-F 6-9am, 4-9pm Off-peak: all other hours
eflat_nflat	$0.06/kWh	Per-kWh: $.06/kWh	N/a
etou_ntou	On-peak: $0.09/kWh Off-peak: $0.04/kWh	Per-kWh: On-peak: $0.09/kWh Off-peak: $0.04/kWh	On-peak: M-F 6-9am, 4-9pm Off-peak: all other hours
eflat_ndem1	$0.06/kWh	Per-kWh: $.03/kWh Capacity: $50/kW DC	N/a
etou_ndem1	On-peak: $0.09/kWh Off-peak: $0.04/kWh	Per-kWh: $.03/kWh Capacity: $50/kW DC	On-peak: M-F 6-9am, 4-9pm Off-peak: all other hours
eflat_ndem4	$0.06/kWh	Per-kWh: $.03/kWh Capacity: WN: $20/kW DC WF: $10/kW DC SN: $18/kW DC SF: $9/kW DC	On-peak: M-F 6-9am, 4-9pm Off-peak: all other hours Winter: October - April Summer: May - September
etou_ndem4	On-peak: $0.09/kWh Off-peak: $0.04/kWh	Per-kWh: $.03/kWh Capacity: WN: $20/kW DC WF: $10/kW DC SN: $18/kW DC SF: $9/kW DC	On-peak: M-F 6-9am, 4-9pm Off-peak: all other hours Winter: October - April Summer: May - September
eflat_nsub4	$0.06/kWh	Per-kWh: $.03/kWh Capacity: WN: $17/kW SC WF: $8/kW SC SN: $16/kW SC SF: $9/kW SC	On-peak: M-F 6-9am, 4-9pm Off-peak: all other hours Winter: October - April Summer: May - September
etou_nsub4	On-peak: $0.09/kWh Off-peak: $0.04/kWh	Per-kWh: $.03/kWh Capacity: WN: $17/kW SC WF: $8/kW SC SN: $16/kW SC SF: $9/kW SC	On-peak: M-F 6-9am, 4-9pm Off-peak: all other hours Winter: October - April Summer: May - September

Table 5.3: Tariffs tested in Massachusetts case study

Alias	**Energy Tariff**	**Distribution Network Tariff at 0% EV**	**Relevant Periods**
eflat_nflat	\$0.15/kWh	Per-kWh: \$.13/kWh	N/a
etou_ntou	On-peak: \$0.23/kWh Off-peak: \$0.11/kWh	Per-kWh On-peak: \$0.20/kWh Off-peak: \$0.10/kWh	On-peak: M-F 6-9am, 4-9pm Off-peak: all other hours
etou_ndem1	On-peak: \$0.23/kWh Off-peak: \$0.11/kWh	Per-kWh: \$0.04/kWh Capacity: \$136/kW DC	On-peak: M-F 6-9am, 4-9pm Off-peak: all other hours
etou_ndem4	On-peak: \$0.23/kWh Off-peak: \$0.11/kWh	Per-kWh: \$.04/kWh Capacity: WN: \$88/kW DC WF: \$0/kW DC SN: \$73/kW DC SF: \$0/kW DC	On-peak: M-F 6-9am, 4-9pm Off-peak: all other hours Winter: November - March Summer: April - October
etou_ndem12	On-peak: \$0.23/kWh Off-peak: \$0.11/kWh	Per-kWh: \$.04/kWh Capacity: \$14/kW-mo DC	On-peak: M-F 6-9am, 4-9pm Off-peak: all other hours

Chapter 6

Results

This chapter is divided into two sections. First, we present the results for the Greensboro case study. Second, we present the results for the Massachusetts case study. For the levelized cost and change in network cost metrics, we present the low ($100/kW) and high ($500/kW) LRMC cases side-by-side. These values represent a range of possible incremental investment costs.

6.1 Results for Greensboro Case Study

We first discuss the results for the growth in annual peak under the different distribution network tariff designs, with one sensitivity analysis on household adherence to price signals. We then analyze the levelized charging cost for EV households. Finally, we discuss distributional impacts. For each metric we group the scenarios by type of energy tariff (flat or TOU) for legibility and to highlight the interaction between energy and distribution network tariff designs.

6.1.1 Greensboro: Annual Peak

Figure 6.1 shows the annual feeder-wide peak demand for each tariff at 5% EV adoption increments, with 0-30% adoption magnified. The annual peak is identical for both LRMC cases so we do not show them separately; under our assumption of perfect rationality, only relative price differences impact each household's response, not the absolute magnitude (which the LRMC affects). For example, if we assume an on-peak tariff price of $0.20/kWh, an off-peak tariff price of $0.19/kWh will induce the same EV response as a price of $0.10/kWh in our model. The *eflat_nfixed*/ *eflat_nflat* and *etou_nfixed*/*etou_ntou* tariffs produce the same result because the distribution network tariff either reinforces or has no distortionary effect on the energy tariff price differences.

Under the flat energy tariff, vehicles charge immediately upon arrival as there is no incentive to delay charging until a later time. This yields an increase in annual peak demand as early as 5% adoption. However, because of natural heterogeneity in vehicle arrival time, aggregate charging demand is spread out over evening hours and peak demand only grows modestly. Under the TOU energy tariff, the price differential induces all EVs that arrive

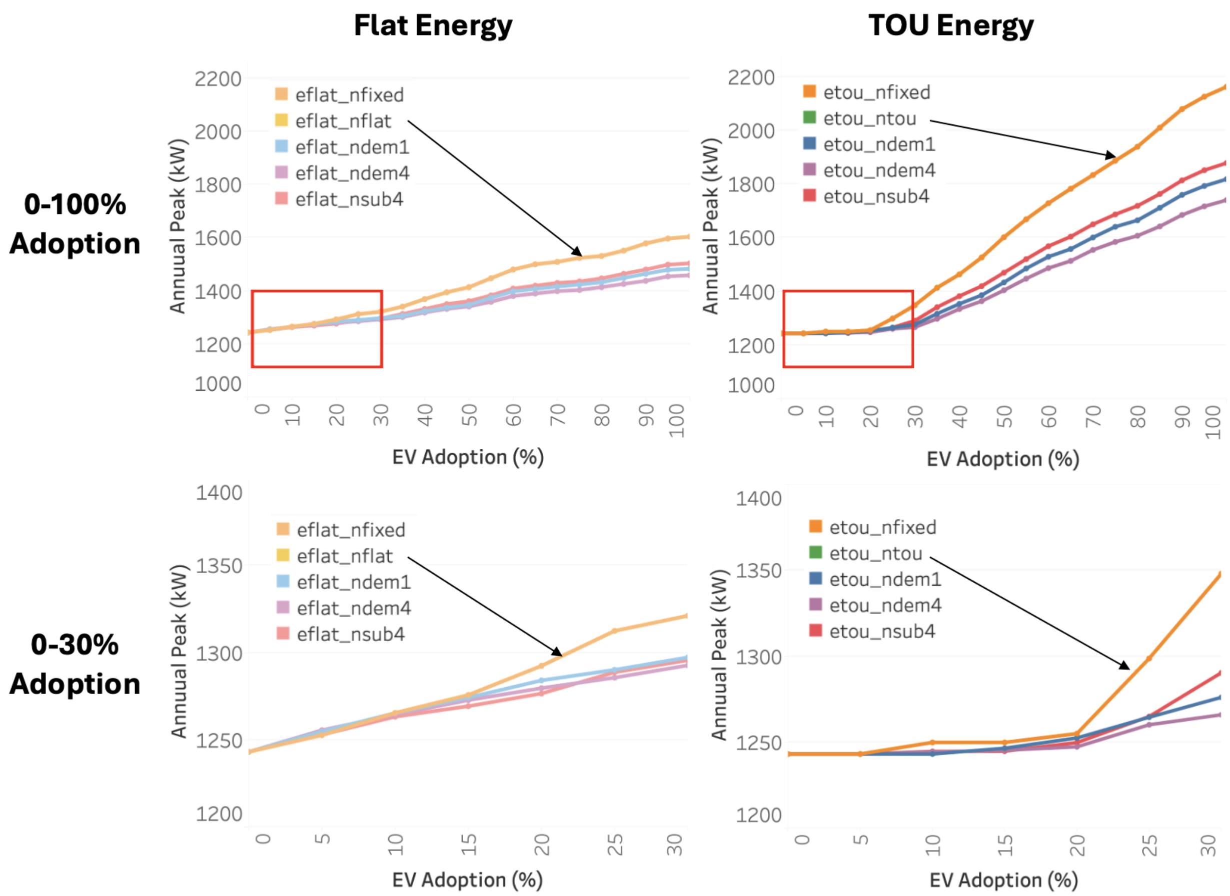


Figure 6.1: Annual peak demand for the Greensboro feeder at 5% EV adoption increments for distribution network tariffs combined with flat (left) and TOU (right) energy tariffs. Top shows full adoption range and bottom shows 0-30% to highlight when peak demand growth begins under each tariff.

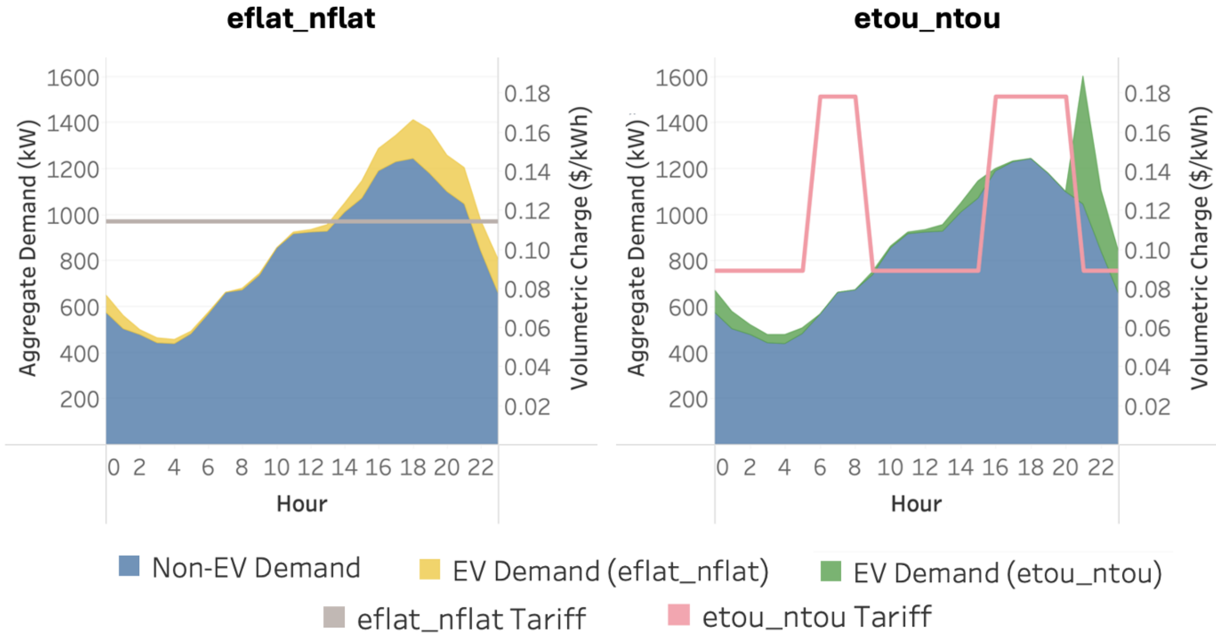


Figure 6.2: Aggregate average weekday demand at 50% EV adoption under the *eflat_nflat* (left) and *etou_ntou* (right) tariff scenarios with tariff prices overlayed. Under the *eflat_nflat* tariff, EV owners charge immediately upon arrival. Under the *etou_ntou* tariff, EV owners schedule charging to delay until the start of the off-peak period.

prior to 9:00 PM to wait until the off-peak period to start charging. This phenomenon is illustrated in Figure 6.2 for 50% EV adoption.

Until 25% adoption, the TOU energy tariff induces charging to shift to hours where the network has excess capacity and so does not increase annual peak demand. However, at 25% adoption and beyond, the correlated response to the off-peak energy tariff produces an EV-driven "rebound" peak that exceeds the historical early-evening peak due to non-EV demand. This effect is most severe under the fixed and per-kWh distribution network tariffs where EV owners charge at the chargers' full capacity. In contrast, capacity and subscription tariffs provide an incentive to charge at a lower capacity to limit the household's maximum instantaneous demand. In this way, even though we still observe an EV-driven peak under the capacity tariffs, the peak is reduced, as shown in Figure 6.3. The flat energy tariff scenarios do not feature the same correlated response; for a given distribution network tariff (e.g., 1-part demand charge), the flat energy tariff produces a lower annual peak compared to the TOU energy tariff at all adoption levels beyond 25%.

For example, at 50% EV adoption, the annual peak under the *eflat_ndem1* tariff is 1,347 kW (an 8% increase over the "baseline" peak demand at 0% EV adoption) compared to 1,432 kW under the *etou_ndem1* tariff (a 15% increase over the baseline). The *etou_ntou* tariff, which provides no incentive for EVs to charge below their maximum capacity at the start of the off-peak period, has an annual peak of 1,601 kW at 50% EV adoption (a 28% increase over the baseline).

We also observe that adding more time periods to the capacity charge improves its ability

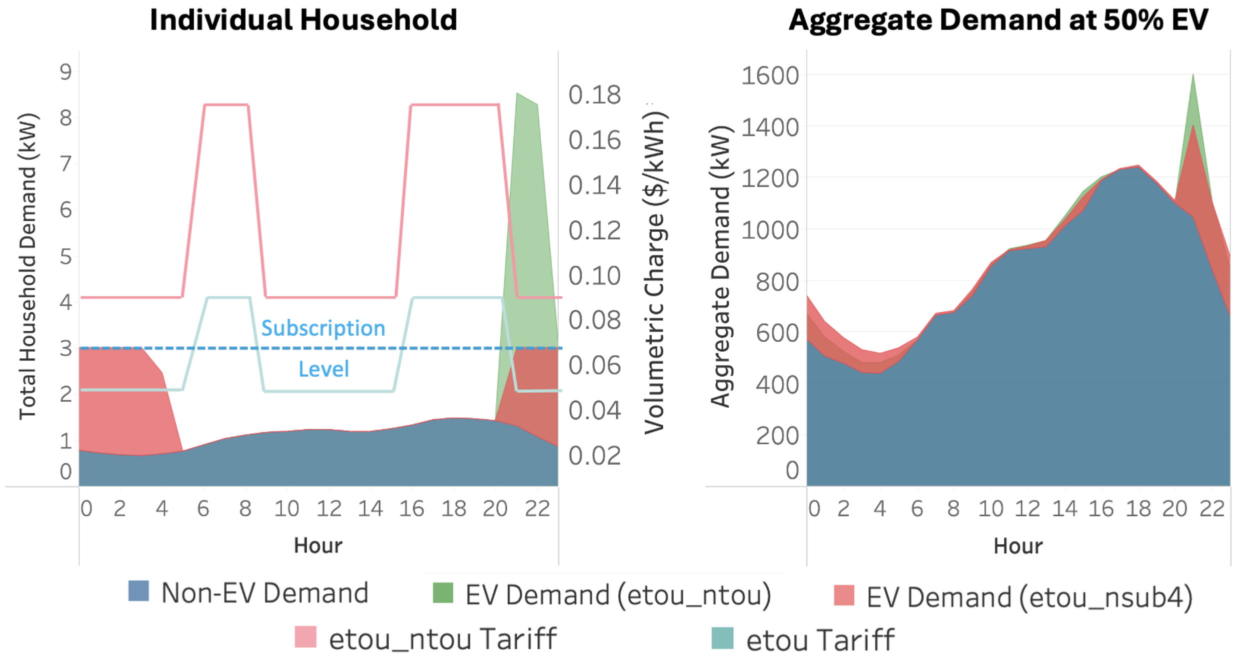


Figure 6.3: Example of an individual household reacting a TOU energy tariff and subscription distribution network tariff (*etou_nsub4*) versus a purely volumetric TOU tariff (*etou_ntou*) (left) and hourly demand aggregated across all households during the annual peak day at 50% EV adoption (right). Note that the scales for the vertical demand axes are not equal. Under a subscription tariff, households still delay charging until the start of the off-peak energy period, but the peak is less pronounced because households have an incentive to manage charging to stay below its contracted capacity.

to mitigate peak impacts and thus to defer network upgrades. This is because under a single capacity period (*ndem1*), the combination of EV and non-EV demand can approach the household's *annual* peak demand (across all hours) without increasing the household's network charge payment. The introduction of intraday and seasonal variation sets a unique maximum level in each period. For most households, their maximum pre-EV demand during off-peak hours is lower than for on-peak hours. This sets a lower target for each household's aggregate demand as it varies the charging capacity level during off-peak hours. When all households behave this way (though still acting independently), it produces a lower annual peak. Under the subscription charge, we lose a portion of peak demand mitigation due to the 1 kW subscription buffer. However, overall, the subscription charge performs better than fixed or per-kWh distribution network tariffs when coupled with either a flat or TOU energy tariff.

We conduct a sensitivity analysis that supposes a small portion of EV households (30%) ignore both the energy and distribution network tariff price signals and charge at full capacity upon returning home. This is designed to test how robust our tariff designs are to "irrational" consumer behavior. We examine the impact on annual peak demand, shown in Figure 6.4. As above, the annual peak values are the same in both LRMC cases, so we do not show them separately.

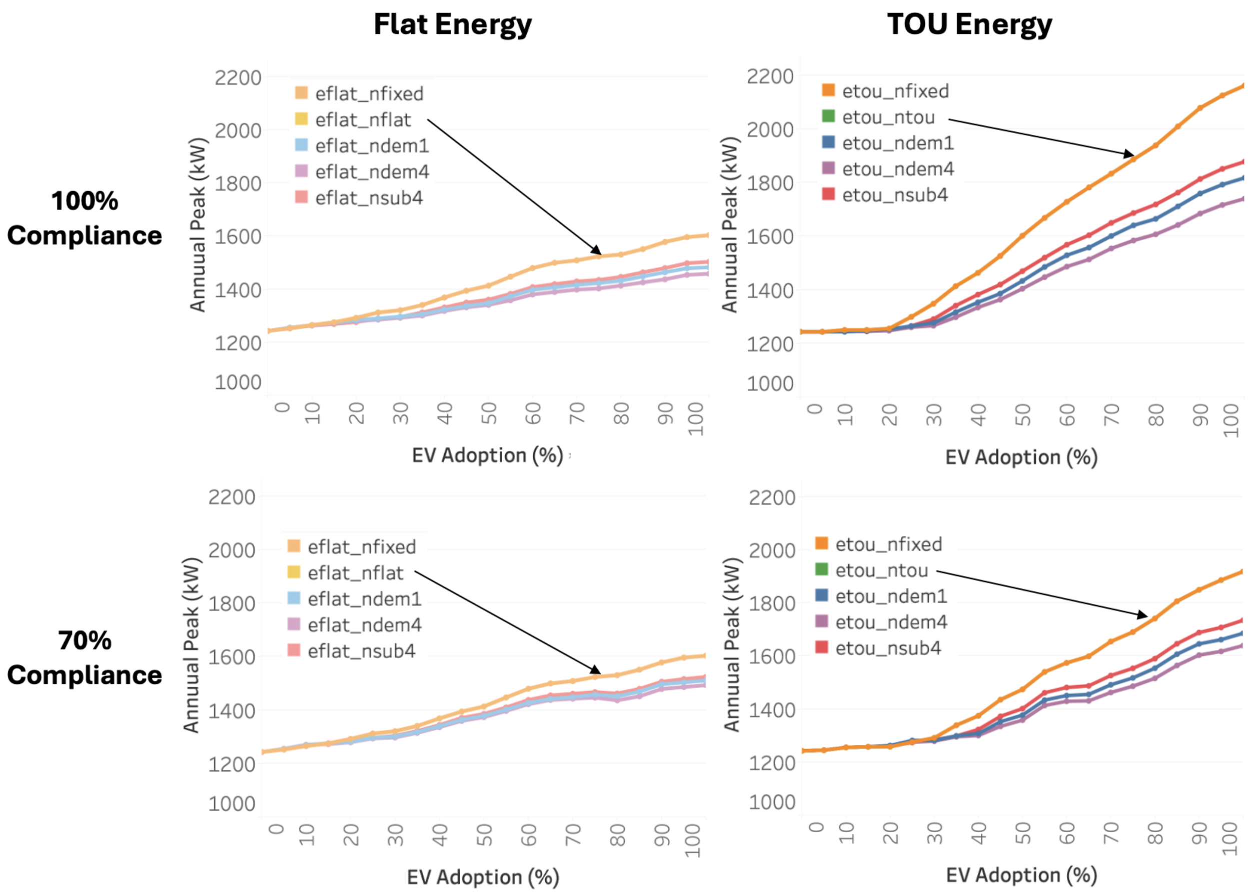


Figure 6.4: Annual peak demand for 100% (top) and 70% (bottom) compliance among EV owners with respect to tariff price signals. When a small number of EV owners deviate from rational behavior, the aggregate peak demand is lower than when all EV owners respond rationally in a correlated manner.

We obtain the somewhat surprising result that with TOU energy tariffs, when 30% of EV owners ignore the price signal and charge immediately upon arrival home at full capacity, the annual network peak is lower than when all EV owners comply. This reflects the fact that with 100% price responsiveness, all EVs that are plugged in charge at the start of the off-peak period. If a portion of EV owners charge immediately upon returning home rather than delaying until lower-priced hours, this introduces heterogeneity that reduces the EV-driven peak demand. This result illustrates that the benefits of capacity charges are not dependent on all consumers responding to them. Note that the effect would be similar if a portion of EV customers elected a flat energy tariff (if that were an option) and reacted to that price signal alone.

For the flat energy tariff, the results are almost identical at 100% and 70% compliance. Under the capacity tariffs, the "irrational" EV households do not manage their charging to minimize their peak demand. Yet if charging at a higher capacity for a shorter period allows them to fulfill their charging needs prior to the start of the off-peak period, this will reduce the magnitude of the "rebound" peak (at the start of the off-peak capacity charge period) as fewer vehicles will be charging then. These phenomena nearly offset to produce a similar aggregate peak for all flat energy tariff scenarios for 100% and 70% compliance.

6.1.2 Greensboro: Levelized EV Charging Cost

Figure 6.5 shows the average levelized charging costs for EV owners under the two energy tariff options and two LRMC cases. Almost all EV households can achieve the lowest theoretical charging cost. This means that they fulfill their driving needs (charging sufficiently to meet usage demand each day) and adhere perfectly to price signals. For the per-kWh tariff component, nearly all EV charging occurs during the off-peak period. For capacity tariffs, EV households manage charging so as not to exceed their pre-EV peak demand in each demand period (or stay beneath their contracted capacity in the subscription tariff). This result is likely an underestimate of charging costs due to our assumption that households can perfectly forecast their individual peak usage. The result for the subscription charge provides a more realistic estimate because customers would know their subscription level in advance and then program EV charging to stay beneath that limit.

Per-kWh distribution network tariffs perform poorly from a levelized charging cost perspective. When the network revenue requirement is collected using a flat per-kWh tariff, EV households contribute more to network cost recovery than under other tariff designs as they have no mechanism to reduce their network costs by shifting demand to off-peak hours. The TOU per-kWh distribution network tariff helps to some extent to lower the levelized costs of charging, but they remain higher than under fixed and capacity-based designs. The upward curve of the values under the high LRMC case reflects the fact that the revenue requirement (driven by annual peak demand) is growing faster than aggregate electricity consumption, which applies upward pressure on the magnitude of the network charge. The energy tariff is exogenous so remains the same at all levels of adoption. The consistent upward curve beyond 20% EV adoption is eliminated in the low LRMC case, where load growth keeps pace with the cost of network upgrades.

Under the subscription distribution network tariff, there is variation in the levelized charging cost paid by EV households, shown in Figure 6.6. This reflects the fact that some

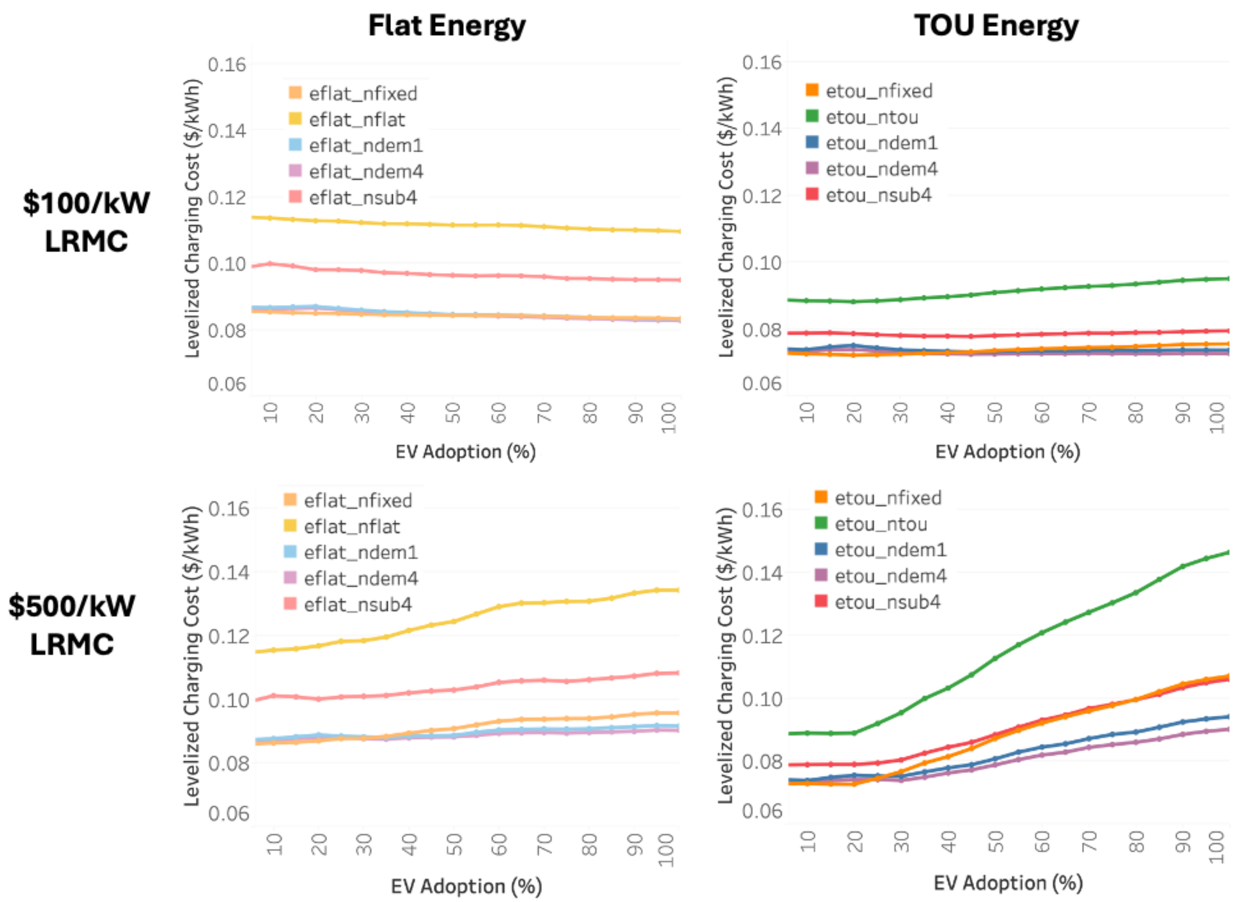


Figure 6.5: Levelized charging costs for EV owners for low (top) and high (bottom) LRMC cases with flat energy tariffs (left) and TOU energy tariffs (right). Almost all EV households can fulfill their charging needs without increasing peak demand or charging during the on-peak per-kWh window. This indicates the high level of flexibility in residential charging activity as cars are plugged in for many hours longer than their charging needs.

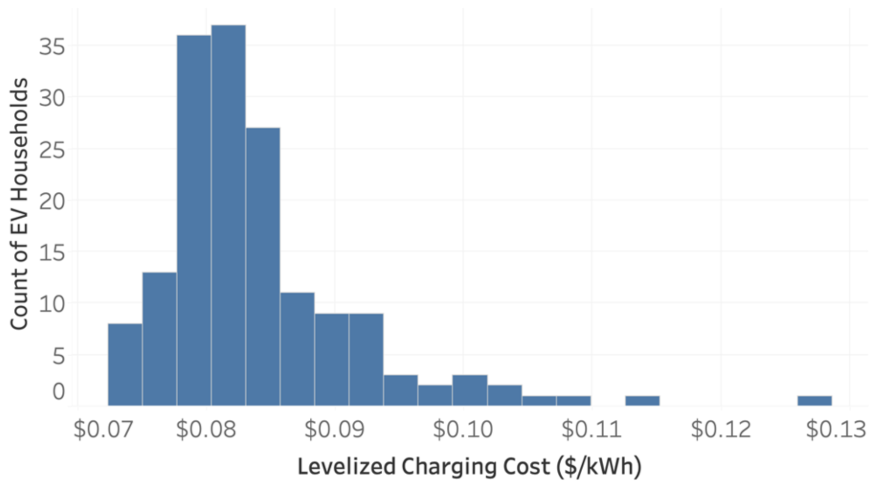


Figure 6.6: Distribution in levelized costs paid by EV households at 50% EV adoption for the *etou_nsub4* tariff scenario.

households must increase their subscription level to allow for sufficient charging time to meet their charging needs.

6.1.3 Greensboro: Difference in Network Costs for Non-EV Households

Figure 6.7 shows the change in annual network costs paid by non-EV households under each distribution network tariff design for both LRMC cases. Positive values reflect cost increases and negative values reflect savings compared to network costs at 0% EV adoption with flat volumetric energy and flat distribution network tariffs (i.e., the baseline).[1] We focus on network costs because those are non-optional in states both with and without retail choice for energy supply. A consumer whose energy tariff costs increase under a TOU plan might be able to opt out and switch to a flat per-kWh energy rate, something we expect to occur in practice, though we do not model this possibility.

An (undifferentiated) fixed distribution network tariff paired with a TOU energy tariff performs the worst at all EV adoption levels, as the majority of new network costs (that are entirely driven by EV charging) are shared equally among all households.[2] Annual peak demand is also highest under fixed charges (see Figure 6.1), as there is no incentive for households to manage charging to limit their maximum demand. This effect is less pronounced under a flat energy tariff whereby charging is not correlated and the peak grows

[1] While EVs account for 1.8% of registered vehicles in North Carolina [147], for simplicity we assume 0% as the baseline.

[2] Though the costs are shared equally, this may be the least equitable outcome in the sense that non-EV households are not responsible for any of the increase in network costs. Included in Joroff's definition of energy justice is "protection from a disproportionate share of costs or negative impacts or externalities associated with building, operating, and maintaining electric power generation, transmission, and distribution systems." [148]

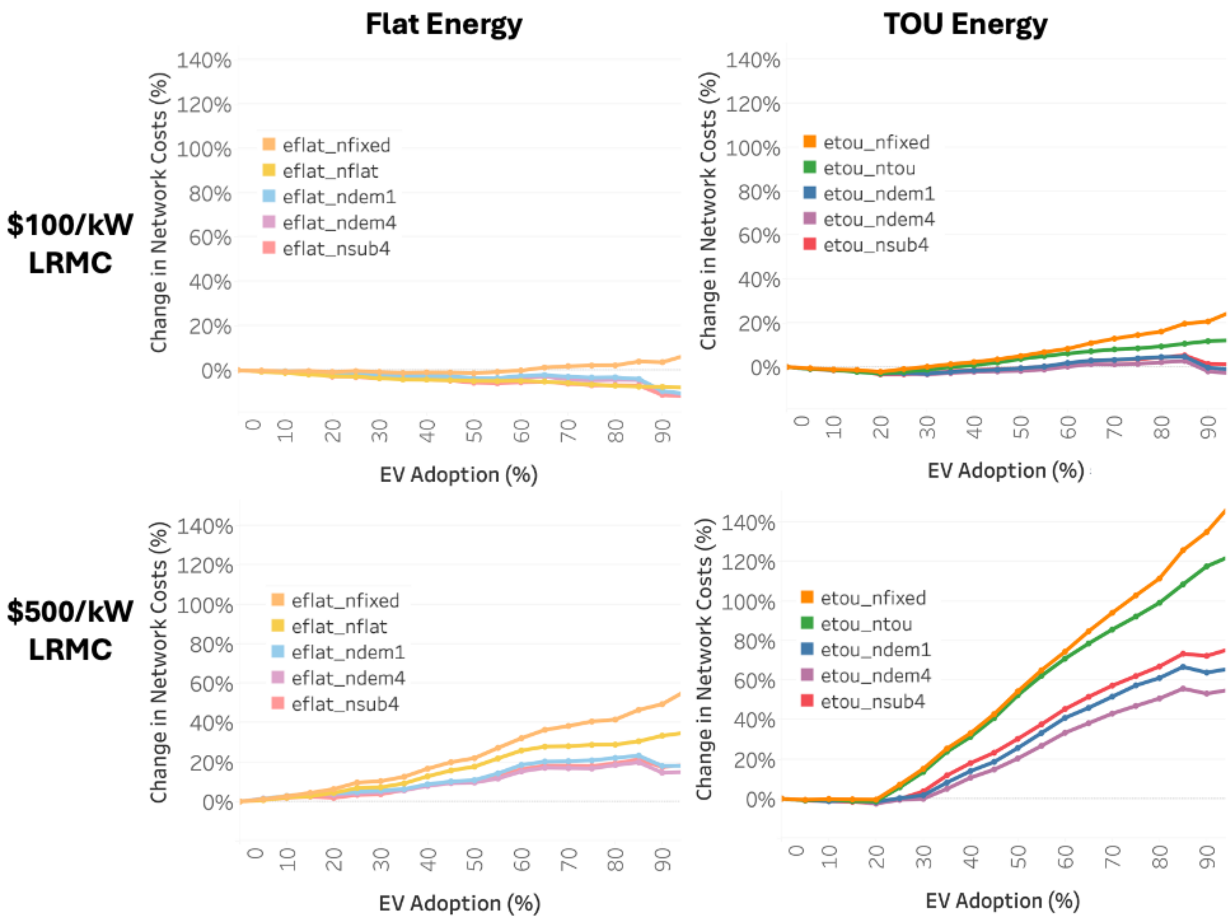


Figure 6.7: Change in network costs for non-EV households for the low (top) and high (bottom) LRMC cases.

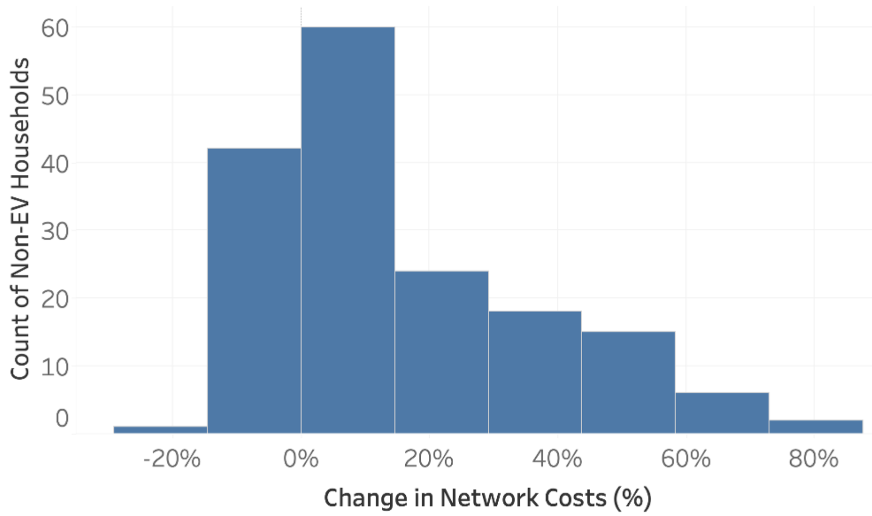


Figure 6.8: Distribution in the change in network cost among non-EV households at 50% EV adoption for the *etou_nsub4* tariff scenario.

more modestly. Including a flat per-kWh charge to collect half the network revenue requirement ensures that even under capacity and fixed tariffs, EV households are contributing to cost recovery at a higher share than prior to EV adoption. Without this charge, the negative impacts on non-EV households would be even more pronounced.

The 4-part demand charge performs best, in large part because the overall revenue requirement that needs to be collected is lowest among all scenarios. While the subscription tariff results in higher revenue collection from EV households compared to 1-part and 4-part demand charges, this benefit to non-EV households is offset partially by the higher annual peak under the subscription tariff.

This metric is highly sensitive to the assumed cost of network expansion. At 50% adoption and an LRMC of $100/kW, the average non-EV household pays at most 5% more than the baseline (with the *etou_nfixed* tariff). Under the flat energy tariff and the capacity network tariffs, non-EV households experience lower costs on average, achieving true "beneficial electrification" whereby the adoption of EVs applies downward rate pressure.

At $500/kW, only at low EV adoption levels do non-EV households see non-negative impacts. At 50% EV adoption, non-EV households pay between 9% and 54% more than their baseline costs so that the utility can recover network upgrades caused by EV charging.

We find significant variability in cost impacts among non-EV households, shown in Figure 6.8. "Peakier" households (those with a high peak demand relative to their annual consumption) will pay more under the capacity tariffs, assuming their consumption patterns do not change.

Undesirable distributional impacts for certain groups (e.g., low-income households) could be mitigated using an ex-post subsidy, but this would need to be funded by other ratepayers or through general taxation; both options would increase the financial burden on other customers [115].

6.2 Results for Massachusetts Case Study

The Massachusetts case study considers electrification of both residential heating and vehicles. CCHPs represent a significant load that is inversely correlated with temperature, especially during winter in cold regions, illustrated in Figure 6.9.

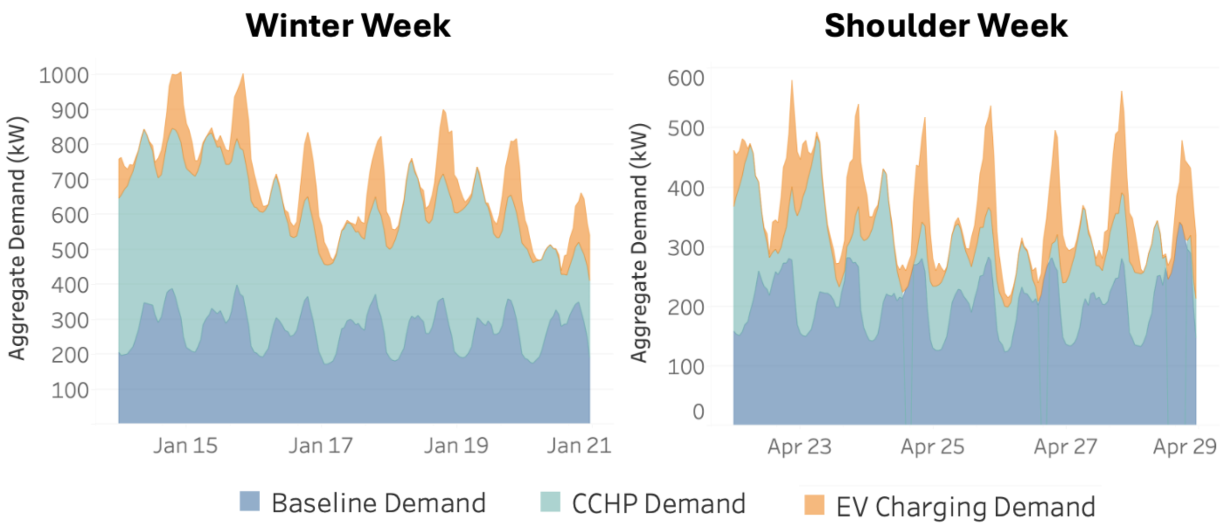


Figure 6.9: Aggregate demand by load type at 50% electrification under the *eflat_nflat* tariff for a cold week (left) and mild shoulder season week (right). During the cold week CCHP demand accounts for 51% of total consumption, compared to 27% during the shoulder week. Note that the axes are not equal.

Like in the Greensboro case, we present the results for annual peak first, levelized operating cost (inclusive of both EV and CCHP) second, and change in network costs for non-electrified households third.

6.2.1 Massachusetts: Annual Peak

Figure 6.10 shows the annual feeder-wide peak demand for each tariff at 5% EV/CCHP adoption increments. The annual peak is identical for both LRMC cases so we do not show them separately. The slight downward dip at early adoption levels is due to the fact that the annual demand occurs in a summer month, and heat pumps cool more efficiently than central AC and window AC units. The circuit flips from a summer- to winter-peaking system at 20% adoption, beyond which there is a sharp rise in peak demand.

Similar to the Greensboro case study, the *etou_ntou* tariff performs worst at all adoption levels starting with 20% due to the correlated response of all EVs starting to charge at the start of the off-peak period with no signal to limit each household's maximum demand. The annual peak is nearly identical for the remaining tariffs. While the demand charge has a mitigating effect on correlated EV charging, the maximum feeder demand under the TOU energy tariff scenarios is driven by electric heating demand during an hour with an outdoor air temperature of -15C (5F).

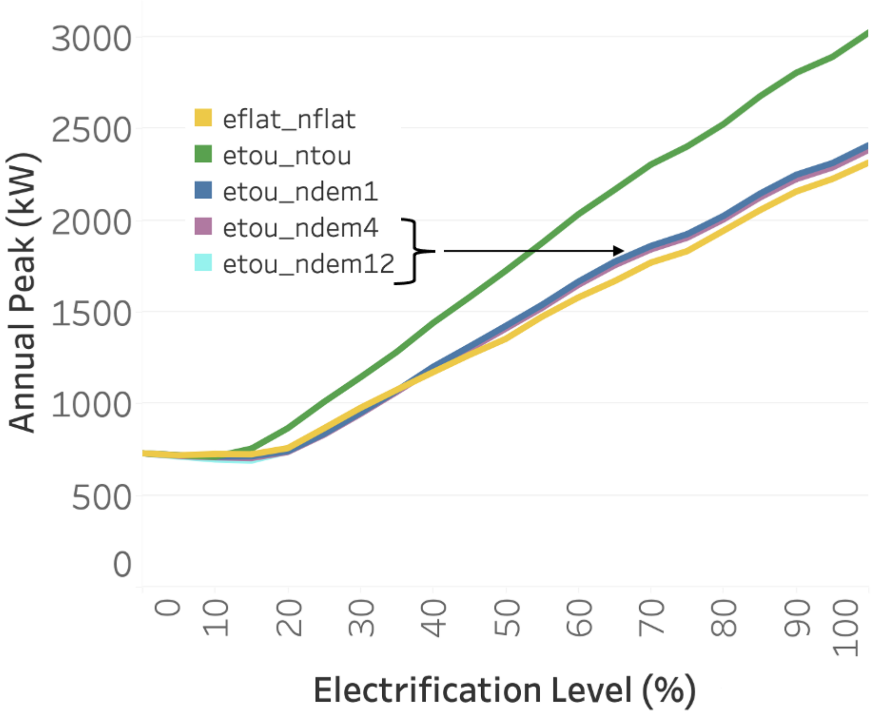
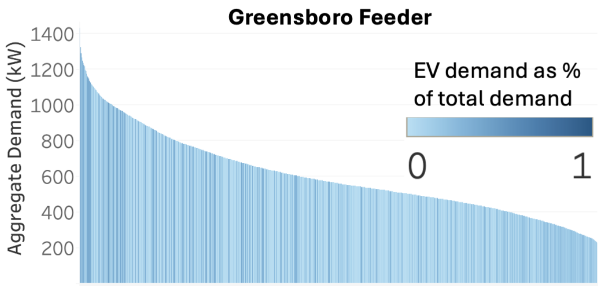


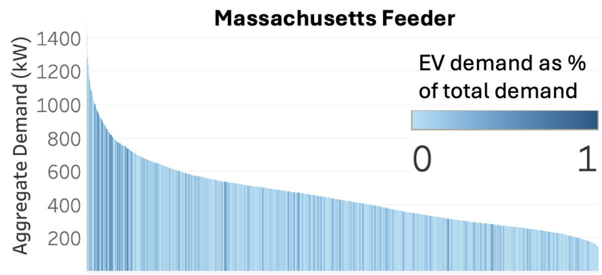
Figure 6.10: Annual aggregate peak demand for the Massachusetts feeder at 5% electrification increments. Beyond very low electrification levels, the peak is driven by electric heating during extreme cold temperatures where demand charges have a negligible mitigating impact.

At extremely cold temperatures, CCHPs must consume at a high capacity to maintain the minimum comfort temperature; neither TOU energy tariffs nor demand charges are effective at shifting consumption during these times. At more moderate temperatures, CCHPs are more flexible; the TOU energy tariff induces a shift in consumption to take advantage of low-price hours by pre-heating and pre-cooling and the demand charge charge incentivizes households to operate their heat pumps at a high load factor rather than running equipment at high capacity for short periods of time.

Figure 6.11 shows a load duration curve at 50% adoption for the Massachusetts feeder compared to the Greensboro feeder for the *etou_ndem1* tariff scenario. Load duration curves show the demand at each hour of the year ranked in descending order. It is purely coincidental that both feeders have an annual peak demand of around 1400 kW. The color of the bar indicates the percentage of the demand due to EV charging. For Greensboro, among the top 25 load hours, 22 of them (88%) occur at weekdays at 9:00 PM (the start of the off-peak window), mostly during summer months. For Massachusetts, only 7 of the top 25 load hours (28%) occur during weekdays at 9:00 PM, and all top 25 hours occur during a cold snap in January. This gap illustrates how geography impacts whether peaks will be "EV-driven" or "CCHP-driven." While capacity-based distribution network tariffs help reduce daily EV peak demand regardless of geography, in cold climates, capacity charges may have only a marginal impact on the annual CCHP-driven peak, which will drive network investment.



(a)



(b)

Figure 6.11: Load duration curves at 50% electrification under the *etou_ndem1* tariff for the Greensboro (a) and Massachusetts (b) case studies. For the Massachusetts feeder, electric heating is the primary cause for high-demand hours. For the Greensboro feeder, it is EV charging.

6.2.2 Massachusetts: Levelized EV/CCHP Costs

Figure 6.12 shows the levelized cost of EV and CCHP operation for electrified households. We report a combined value that indicates the total change in cost post-electrification divided by total change in consumption, averaged across all electrified households. Similar to the Greensboro case study, we see that time-differentiated capacity tariffs achieve reductions in the levelized cost compared to the status quo. For example, at 50% adoption and $100/kW LRMC, the *etou_ndem12* tariff has a levelized cost $0.09/kWh lower than the *eflat_nflat* tariff, a reduction of 25%. As a point of reference, a $0.09/kWh difference has the same impact on operating charging costs for EVs as a $0.70/gallon difference for gasoline vehicles.[3] Furthermore, under the low LRMC scenario, levelized costs decrease over time, which reflects the downward rate pressure as electricity consumption grows faster than network investments. While electrification is defined exogenously in our model, in reality lower electricity costs would likely accelerate electrification [19], lowering costs further in a positive feedback loop.

The 1-part demand charge performs notably worse than the time-differentiated demand charges. This occurs because electrified households pay based on their maximum demand across the whole year, which is likely to occur during extreme cold temperature periods when their CCHP systems are operating least efficiently. Time-differentiated capacity charges in which customers pay based on their maximum demand in each period lessen the influence of high winter heating demand on annual costs. We note that this time differentiation would be less effective if a larger portion of network costs were collected in the winter period (for the *ndem4* tariff) or in the winter months (for the *ndem12* tariff) rather than collecting an equal share of the revenue requirement in each season or implementing a single monthly capacity charge.

[3]This assumes the US average EV and gasoline efficiencies [22].

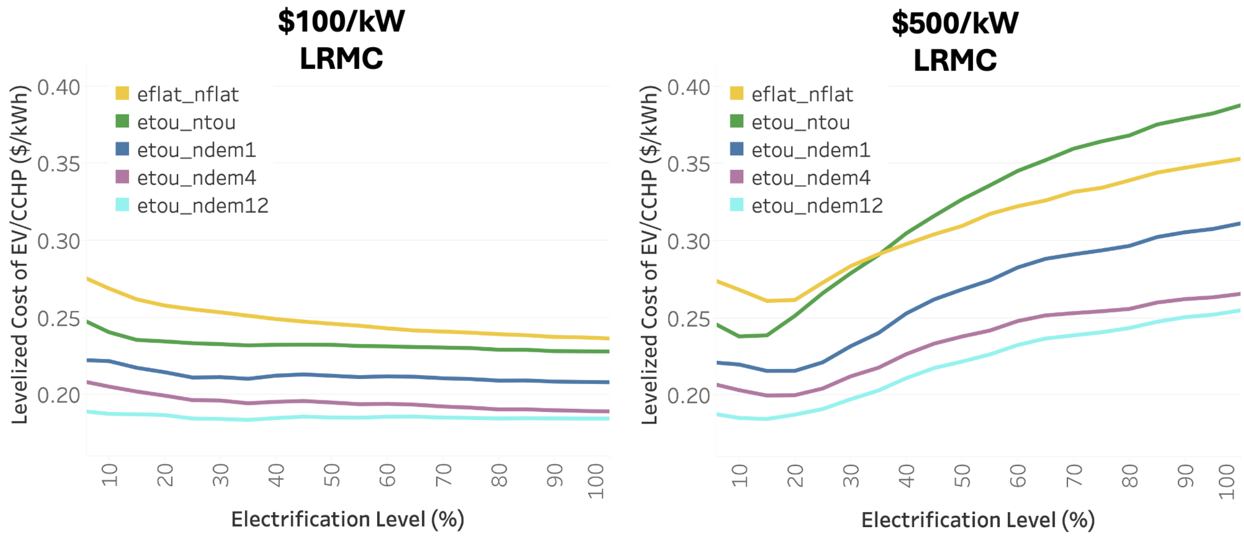


Figure 6.12: Levelized cost of EV and CCHP operation at 5% electrification adoption increments for the low (left) and high (right) LRMC cases.

6.2.3 Massachusetts: Difference in Network Costs for Non-Electrified Households

Figure 6.13 shows the change in network costs for non-electrified households. Under the low LRMC case, non-EV households experience cost reductions under all tariffs at almost all electrification levels. In this case, the growth in annual peak demand (and associated network investment) is offset and surpassed by load growth due to EVs and CCHPs. For the high LRMC case, this phenomenon is only true at low adoption levels when the annual peak demand is stagnant. Non-electrified households face steep rises in costs under scenarios where households can reduce their network contributions by shifting the timing of EV and CCHP consumption. Unlike in the Greensboro case study, where these actions helped avoid network costs increases, in the Massachusetts case study the demand charge has a negligible effect on annual peak compared to the *eflat_nflat* tariff. The 1-part demand charge is the most cost-reflective of the three demand charge options. Electrified households contribute at the highest share to incremental investment costs due to an increase in their annual individual peak demand driven by CCHP heating. With time-differentiated capacity tariffs, the annual peak is unaffected but electrified households contribute less towards the revenue requirement because they can reduce demand during non-winter periods. This shifts a larger portion of incremental investment costs to non-electrified households compared to the 1-part demand charge.

In this chapter, we presented the results from two realistic case studies addressing the long-term impacts of distribution network tariff design on network investments, electrification costs, and distributional outcomes for non-electrified households. The next chapter discusses the implications of our findings.

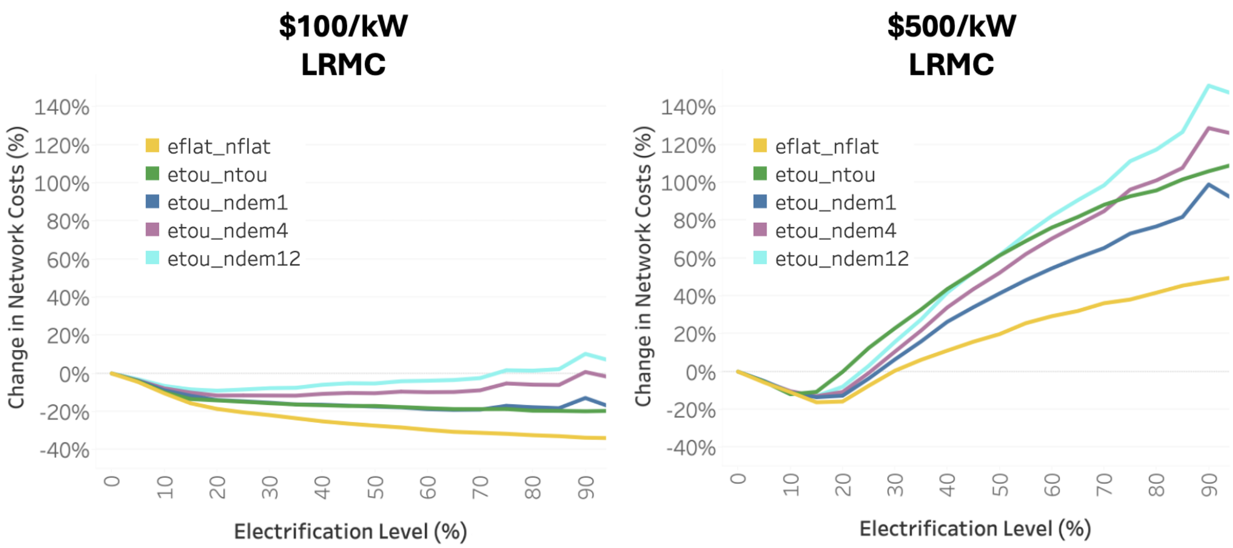


Figure 6.13: Change in network costs for non-electrified households at 5% EV/CCHP adoption increments for the low (left) and high (right) LRMC cases. For the low LRMC case, cost reductions are achieved for all tariffs through 50% EV adoption. For the high LRMC case, this is only true at low adoption levels before network costs steeply rise.

Chapter 7

Discussion

In this chapter, we first provide a brief assessment of the results presented above. Next, we discuss tradeoffs in tariff design and implications of our findings. Finally, we discuss limitations of our modeling approach.

7.1 Assessment of Model Results

Tables 7.1 and 7.2 provide a summary of the key metrics in the Greensboro and Massachusetts case studies, respectively, at 50% electrification. Note that 50% adoption in concentrated areas of the grid can happen earlier than statewide 50% adoption. In each table, colors indicate how well each tariff performs (green being the best, red being the worst). Colors are assigned independently in each column to reflect that the two LRMC cases do not interact.

Scenario	*Energy Tariff*	*Network Tariff*	*Annual Peak (kW)*		*Levelized Charging Cost ($/kWh)*		*Change in Network Cost for non-EV homes (%)*	
			$100/kW	*$500/kW*	*$100/kW*	*$500/kW*	*$100/kW*	*$500/kW*
eflat_nfixed	Flat	Fixed	1413		$0.08	$0.09	-1%	22%
eflat_nflat	Flat	1-part Per-kWh	1413		$0.11	$0.12	-5%	18%
eflat_ndem1	Flat	1-part Demand Charge	1347		$0.08	$0.09	-3%	11%
eflat_ndem4	Flat	4-part Demand Charge	1341		$0.08	$0.09	-4%	10%
eflat_nsub4	Flat	4-part Subscription Charge	1360		$0.10	$0.10	-6%	10%
etou_nfixed	TOU	Fixed	1601		$0.07	$0.09	5%	54%
etou_ntou	TOU	2-part TOU Per-kWh	1601		$0.09	$0.11	4%	52%
etou_ndem1	TOU	1-part Demand Charge	1432		$0.07	$0.08	0%	26%
etou_ndem4	TOU	4-part Demand Charge	1403		$0.07	$0.08	-2%	20%
etou_nsub4	TOU	4-part Subscription Charge	1469		$0.08	$0.09	0%	30%

Table 7.1: Key metrics in the Greensboro case study for each tariff at 50% EV adoption for low and high LRMC cases

The results in Tables 7.1 and 7.2 indicate a trade-off in assessment criteria. For example, in the Greensboro case study, the *eflat_nflat* tariff performs well for the change in network costs for non-electrified homes but poorly in levelized operating costs as EV and CCHP

Scenario	Energy Tariff	Network Tariff	Annual Peak (kW)		Levelized EV/CCHP Operating Cost ($/kWh)		Change in Network Cost for non-electrified homes (%)	
			$100/kW	$500/kW	$100/kW	$500/kW	$100/kW	$500/kW
eflat_nflat	Flat	1-part Per-kWh	1353		$0.25	$0.31	-27%	20%
etou_ntou	TOU	2-part TOU Per-kWh	1725		$0.23	$0.33	-17%	61%
etou_ndem1	TOU	1-part Demand Charge	1424		$0.21	$0.27	-17%	41%
etou_ndem4	TOU	4-part Demand Charge	1410		$0.19	$0.24	-10%	52%
etou_ndem12	TOU	Monthly Demand Charge	1417		$0.19	$0.22	-5%	61%

Table 7.2: Key metrics in the Massachusetts case study for each tariff at 50% EV adoption for low and high LRMC cases

households have no opportunity to save money by shifting the timing of their consumption. The opposite is true for the *etou_nfixed* tariff, under which levelized operating costs are low but new network investments are shared equally among all households, resulting in the highest in network costs for non-electrified homes among all tariffs.

Capacity-based tariffs (demand and subscription charges) offer a compromise, providing a reduction in levelized charging cost compared to the per-kWh tariffs while shifting costs to non-electrified households by only a modest amount compared to the worst-performing fixed tariff. Capacity tariffs also mitigate annual peak compared to tariffs under which households have no incentive to limit the instantaneous demand of their EVs or CCHPs. This effect is more pronounced in the Greensboro case study in which peaks are EV-driven. In the Massachusetts case study (where peaks are CCHP-driven during extremely cold hours) capacity charges have only a small impact on annual peak demand at high levels of adoption. However, capacity tariffs still achieve significant reductions in levelized costs for EVs and CCHPs compared to per-kWh tariffs.

In the Greensboro case study, scenarios with flat energy tariffs broadly perform better than those with TOU energy tariffs for annual peak (and associated network investment costs). Despite this result, we do not believe regulators should attempt to retain flat energy tariffs, which we discuss below.

Our results also demonstrate the role of the long-run marginal cost in determining whether electrification will have an upward or downward effect on tariff prices. In service territories with high marginal network expansion costs, regulators may prefer tariffs that better protect non-electrified households even if this means higher levelized costs for new electrified load. In contrast, where marginal investment costs are low, regulators may prefer tariffs that reduce the operating costs of EVs and CCHPs to accelerate electrification, confident that the impact on non-electrified households will be beneficial. In the low-LRMC scenario, reducing costs of ownership for EVs and CCHPs (a priority for many US states) is wholly compatible with the pursuit of broader energy affordability goals.

7.2 Tariff Design Considerations

Our results suggest that there is no “one size fits all” solution for tariff design in all geographies. Approaches that effectively mitigate EV-driven rebound peaks in the Greensboro case study are not as effective when we consider the concurrent electrification of heating and transportation in a cold climate. In areas like the southeast US with mild winter temperatures where there is already high electric heating penetration [140], a time-differentiated capacity tariff where households have an incentive to minimize their peak demand at all hours appears to balance stakeholder interests while mitigating peak demand growth. On the other hand, in cold climates where heating-driven peaks are expected, a subscription charge may be counterproductive; regulators may wish instead to provide even stronger incentives than modeled in this thesis for households to pre-heat at high demand during the mid-day and overnight hours. This could mitigate CCHP-driven early morning and evening peaks. For example, they could create a "super off-peak" energy tariff period (i.e., \$0/kWh) or offer peak time rebates during extremely cold days.

As regulators design new distribution network tariffs, they should consider not only geographic factors (i.e. winter- or summer-peaking systems) but also the unique drivers for consumer adoption of EVs and CCHPs. While electricity cost is a factor in EV purchases, consumers rank upfront purchase price and public charging availability as much more significant adoption barriers [149]. Furthermore, Bushnell et al. [20] show that gasoline prices have a larger effect (four to six times) in California on EV adoption compared to electricity prices, and even under the flat volumetric tariffs prevalent today, electricity enjoys a significant operating cost advantage over gasoline in almost all US states [21]. For these reasons, it may be acceptable to design a tariff that does not reduce the levelized charging cost for EVs significantly (e.g., only a modest price differential between peak and off-peak per-kWh charges or recovering a higher percentage of the network cost via a per-kWh charge).

In contrast to EVs, Davis [19] finds CCHP adoption is strongly correlated with electricity prices. In states like Massachusetts and California where natural gas is the dominant space heating fuel [8], current (high) electricity prices render heat pump adoption uneconomic [27] even before equipment and installation costs are considered.[1] Maine, which has achieved the highest CCHP adoption rate among cold-weather states with over 100,000 systems installed, also has the highest percentage of homes heating with propane or fuel oil (65%) [8], which are expensive relative to piped gas in other parts of the country. Maine's space heating expenditures per household are sixth highest among all US states (6th) [8]. Reducing the operating costs for heat pumps is therefore essential to achieving decarbonization targets in states where gas is primarily used for heating. In the absence of explicit subsidies (e.g., Central Maine Power's seasonal heat pump rate), allocating a higher portion of network cost recovery to fixed or time-differentiated capacity charges (which in our Massachusetts case study reduces the operating costs by as much as 32% compared to the status quo) is one potential solution to this challenge.

A tariff that effectively both encourages high-demand pre-heating/pre-cooling for CCHP systems and mitigates EV rebound peaks may not be possible while meeting other tariff design objectives (especially simplicity). For some regulators, the distinct operating characteristics of EVs and CCHPs may suggest designing separate tariffs for each technology. While some utilities have offered EV-specific rates (with consumption measured by the ve-

[1] Addressing the negative externalities of emissions directly (i.e., via a price on a carbon) would provide incentives to switch from gas; its social cost with a carbon price is higher than its private cost without a carbon price [150].

hicle or charger), this has not been attempted at scale for CCHP systems, and it remains unclear if it is technically possible without the use of a secondary meter. Furthermore, designing technology-specific rates would violate long-held norms in rate design and risk exacerbating distributional impacts if only households with either EVs or CCHP systems would be able to reduce their costs by shifting the timing of consumption. Tariffs should be technology-agnostic, non-discriminatory, and reflect expected consumer responses, including highly correlated responses due to load automation.

Finally, we note that the theoretically most efficient distribution network tariff consists of two parts: a capacity charge based on forward-looking costs and a differentiated fixed charge to recover sunk network costs. However, an income-based fixed charge proposal has faced significant opposition in California [151], [152], and we do not believe this to be a pragmatic path forward.[2] Instead, we recommend recovering a portion of the total revenue requirement via a flat per-kWh charge and a portion via a subscription charge[3] (with the exact split determined by the regulator to balance policy objectives). This solution gives consumers more control over their costs compared to a static fixed charge, is a less drastic departure from the status quo, does not require utilities to collect income information, and has a mechanism (the flat per-kWh charge) to protect non-electrified households from increasing network costs. In the subsections below, we address additional tariff design considerations.

7.2.1 Addressing the Apparent Benefits of Flat Volumetric Tariffs

In the Greensboro case study, paradoxically, at high levels of EV adoption, the *eflat_nflat* scenario (the status quo today) achieves a lower annual peak demand than any distribution network tariff paired with TOU energy tariffs. When there is no incentive to delay charging, each vehicle charges upon arriving at home at the maximum charger capacity. Differences in arrival times introduce heterogeneity, and aggregate peak demand is lower than the correlated "snapback" or "rebound" we observe with a TOU energy tariff. This begs the question: if the status quo tariff performs so well, then why move away from it?

As Figures 6.5 and 6.12 show, the status quo tariff has one major drawback: the effect on the levelized costs of electrified devices. When households have no opportunity to save money by shifting demand, they pay the highest price among all scenarios at almost all electrification levels. While this may not be a significant barrier to EV adoption [149], households are unlikely to purchase CCHP systems if they cannot achieve a modest payback period on their investment [19], especially in retrofit applications where they are supplementing or replacing an existing heating system that may not have yet reached the end of its life. This requires moving away from flat volumetric tariffs, under which the payback period is infinite in some states, even with lucrative purchase incentives.

For each distribution network tariff, we observe better annual peak and distribution impact performance for the flat energy tariff. Yet flat energy tariffs may be unrealistic for three key reasons. First, in states with retail choice, retailers only control the energy tariff

[2] Opposition to the IGFC was not uniform. There are ideological objections to income related fixed charges. Rooftop PV interests objected because they expected that a high fixed charge would reduce the value of net metering. There were also general objections to "radical" changes and support for continuity in rate design.

[3] Below, we explain why we prefer subscription charges over demand charges.

component of the bill, and their procurement costs are tied to wholesale electricity prices. This creates an incentive for retailers to design energy tariffs that encourage customers to consume at hours with low wholesale prices regardless of the conditions on the local distribution grid. Regulators have no oversight over the design of energy tariffs by retail suppliers.

Second, in states without retail choice, there are other considerations besides those related to the distribution network that impact tariff design decisions, for example reflecting the short-run marginal cost of generation and enabling the interconnection of additional renewable energy [153]. Reflecting these conditions in the energy tariffs requires a time-varying signal, which may not align with local network congestion.

Third, flat energy tariffs represent an unstable equilibrium. While they produce a favorable global outcome (lower network costs), EV drivers will opt for TOU rates when they are available because the potential for savings is considerable, as shown by Borlaug et al. [154]. Almost all utilities offer opt-in TOU rates today. And while some utilities may believe that they can achieve demand shifting using only behavioral nudges, Bailey et al. [130] show that when financial incentives are removed, the timing of charging reverts to the original schedule (i.e., charging immediately upon returning home).

For these reasons, we do not believe that regulators should attempt to prevent time-varying energy tariffs in the interest of reducing local peak demand growth. Our results show that well-designed distribution network tariffs can mitigate some of the negative impacts of TOU energy tariffs.

7.2.2 Subscription versus Demand Charges

The Greensboro case study shows that when paired with an energy TOU tariff, a multi-part demand charge is the most effective at reducing peak demand growth.[4] This is partly the result of the perfect foresight that each household possesses when determining how to schedule its EV load. However, even if it were realistic to expect that demand charges would produce the most efficient results, we do not believe that states should adopt demand charges for residential consumers. Subscription charges (which do not perform badly on any of the key criteria in the Greensboro case study) offer implementation advantages over demand charges, as discussed below. As PUCs attempt to balance stakeholder interests in promoting electrification while addressing the problem of correlated rebound peaks, a tariff design that does not create big winners or losers may be the most palatable.

US utilities that have pushed back against time-varying rates often cite customer confusion and expected bill impacts as the reason for their opposition (see, e.g., [156]). Because utilities are penalized for customer confusion and bill shocks, utilities may oppose complicated tariff designs. Hennig et al. [119] acknowledge this fact, including "simplicity" and "implementation burden" as core criteria for network tariff assessment. There are also experimental studies that show that highly complex tariffs blunt consumer responses (e.g., [157]).

Nothing in everyday consumer spending resembles demand charges. For customers ac-

[4]This and the following subsection were adapted from a manuscript that is currently under review for publication [155].

customed to paying flat volumetric charges and unaware of their consumption at any given moment, the concept of being charged based on their maximum demand may be an unacceptably large change. Under demand charges, customers are often not shielded from risk; accidentally running multiple appliances concurrently for a few minutes could result in hundreds of dollars in incurred costs. A demand charge also suffers from the opposite problem: for knowledgeable customers who set a high kW demand early in a billing period, there may be no incentive to manage power demand for the remainder of the period, leading to higher aggregate peak demand.

Thus, while demand charges perform well in our simulations, consumers may resist them, and regulators may be averse to implementing them. We believe subscription charges overcome these problems in several ways.

First, a subscription charge has a cognitive advantage; it gets consumers' attention and makes optimization easier. If a customer must subscribe in advance and is prompted to resubscribe from time to time – e.g., with estimated savings and a default option to continue at the same level – it forces them to think about how they can minimize costs. When the demand charge gets buried in the overall tariff, consumers may not focus their attention on cost minimization.

Second, the subscription structure is similar to popular phone and internet plans, wherein customers pay for a maximum level of service that cannot be exceeded without incurring penalties. A familiarity with these types of plans will help explain the logic of subscription charges and ease the transition to new distribution network tariffs.

Third, a subscription can be implemented in a way that protects consumers from high bills. For example, smart meters can be programmed such that if demand exceeds the subscribed level for some time (e.g., 5 or 15 minutes), the meter is temporarily disconnected. This immediate feedback will help coach customers to not turn on high-power devices simultaneously or to purchase devices that make it possible to program which appliances get turned off first [158]. If meters are tripped frequently due to exceeding the subscription level and customers want to increase their subscription, they may do so for the following billing period.[5]

Fourth, a subscription offers more bill certainty, which is important for customers on tight monthly budgets. Even without perfect foresight, customers can better predict their costs using their ex-ante contracted value compared to an ex-post charge. There are several variants of subscription charges (e.g., "smart subscriptions") that could be used in a transitional period, for example starting out using a soft cap with a small penalty fee calculated as a function of when the subscription value is exceeded, eventually shifting to a hard cap [159].

Fifth and finally, having customers sign up for the maximum demand to which they want access provides information that can help utilities to plan future networks. Even if customers change or exceed their subscriptions, knowing each household's expected peak consumption (which may be significantly lower than their service connection) is a valuable input for distribution resource planning.

These benefits may help explain why several EU member states have already adopted

[5] Frequent adjustment may be penalized, though. In Spain, for example, there is one free adjustment per year. After that, customers are penalized for increasing their subscription level.

per-kW subscription charges. A 2023 ACER report on network tariffs highlights examples from Italy, Portugal, Spain, and Slovenia, among others, and recommends a "gradual move to increasingly power-based distribution tariffs to recover those costs which show correlation with contracted or peak capacity" [131]. Because of extensive retail competition, European countries tend to have electricity bills in which different cost categories (transmission, distribution, supply, etc) are broken out. This makes it easier to implement a subscription charge for just the distribution network portion of the bill. Of course, there is no reason why US states without retail competition could not disaggregate their electricity bills as well. In states and countries with retail competition, the distribution (wires) provider could help educate customers on selecting the proper subscription level.

Despite these advantages, we are not naive about the difficulty of implementing what for US consumers would be a radical departure from the rates they have been accustomed to for decades. Techniques like shadow billing – whereby consumers continue paying under the legacy tariff but see what they would have paid under the new tariff – can be helpful to both protect and educate customers during the transition period. Given the time required to develop new rates and how quickly the issue of rebound peaks may appear, states that have not yet transitioned away from flat volumetric rates should consider consider per-kW subscription charges as a component of retail rate reforms in addition to TOU and critical peak energy pricing.

7.2.3 Direct Load Control

We deliberately chose not to model direct load control, whereby a utility or third-party aggregator modulates the consumption of customer-sited devices to achieve some operational objective (e.g., minimize peak demand). From a technical perspective, we know that direct load control is effective at mitigating the rebound peak problem in distribution grids, demonstrated in the literature [160], [116], [125], [76] and several small-scale pilots over the years [161], [162]. But despite this knowledge, such programs have not been deployed at scale anywhere in the world, even in countries recognized as leaders in utility regulation. We believe three types of barriers – behavioral, technical, and regulatory – would have to be overcome to successfully roll-out centralized load control programs at scale to mitigate local distribution peaks in the US.

First (behavioral), existing load-control programs (e.g., smart thermostat demand response) have proven popular and effective at addressing resource adequacy challenges at the bulk system level. These involve very infrequent load control actions (a few hours per year) that in effect substitute for dramatic price spikes. Load control to address peak kW demands within local distribution grids has different characteristics and would require frequent utility control of household demand (perhaps daily). Consumers may not accept such frequent interventions. Of the three barriers, this is likely the easiest to overcome if there are options for consumers to override control signals.

Second (technical), resource adequacy issues at the bulk system level have been monitored in detail by Independent System Operators for decades. Efficiently applying load control for local constraints requires granular visibility of flows at the distribution level. Currently, so-called "smart grids" are in early-stage development. Price signals at the wholesale level indicate when constrained system situations occur and provide information about the value of centralized load control for resource adequacy. Utilities or retailers (in states with retail competition) are subject to these price signals. No such price signals exist currently at the distribution level. Distribution investments are typically made many years in advance and align with a long-run price signal rather than fluctuating spot market prices.

Third (regulatory), under the cost-of-service regulatory model dominant in the US, distribution utilities have an incentive to deploy capital whereas direct load control reduces the need for capital investment. Even if regulators could compel utilities to develop load control platforms, evaluation of program payments to participating customers would not be straightforward. In states with retail choice, effective load control would require the distribution utility to provide price signals, which could change daily, to retailers, who could then directly pass them through to their consumers. The development of such a regulatory framework and pricing mechanism would be highly complex and could take years to implement.

Given the complexity of these barriers, we have little reason to believe that all three will be solved quickly. The potential rapid growth in EV and CCHP penetration points to a need for simple alternatives like tariff design to reduce unnecessary investment in distribution grids. Whereas it is relatively simple for a regulatory agency to compel a utility to implement a new default rate structure, mandating load control to mitigate local grid issues – which has no historical precedent – would likely take more time and face significant opposition. Over time, the addition of targeted load control or randomization on top of well-designed tariffs could provide even more savings for customers. This is especially true in regions where CCHP-driven peaks can be mitigated with a small number of control events per year (like in our Massachusetts case study), indicated by the steepness of the load duration curve in Figure 6.11. We believe load control and tariff design are complements rather than substitutes, and we intend to address this interaction in future work.

7.2.4 Hybrid Heating Systems and Gas Network Cost Recovery

In the Massachusetts case study, CCHPs operating at low efficiency at extremely cold outdoor temperatures produce large increases in peak demand; at 50% electrification, the feeder's annual peak is between 85% and 136% higher than at 0% electrification, depending on the tariff scenario. CCHP-driven peaks have also been studied at the bulk system level in New England; Khorramfar et al. project that electrifying space heating in all residential buildings in New England will increase winter peak demand by 184% [72].

There is an opportunity for hybrid heating systems, which use both a heat pump and supplemental furnace or boiler, to mitigate this issue. Massachusetts currently requires homeowners to remove their legacy heating systems when claiming an upfront purchase rebate for a CCHP system [143]. While this approach may achieve the highest possible reduction in emissions for each home by eliminating direct fossil fuel combustion, our results indicate that Massachusetts' policy may cause unintended grid issues beyond low adoption levels that ultimately slow the pace of decarbonization. Instead, homes could use their legacy heating systems to meet heating demand during the coldest hours of the year when CCHP efficiency is lowest. Integrated thermostats can be programmed to run either the CCHP, backup system, or both in tandem depending on operating costs or outdoor temperature. Figure 7.1 illustrates this potential; it includes the annual peak results for two tariff scenarios

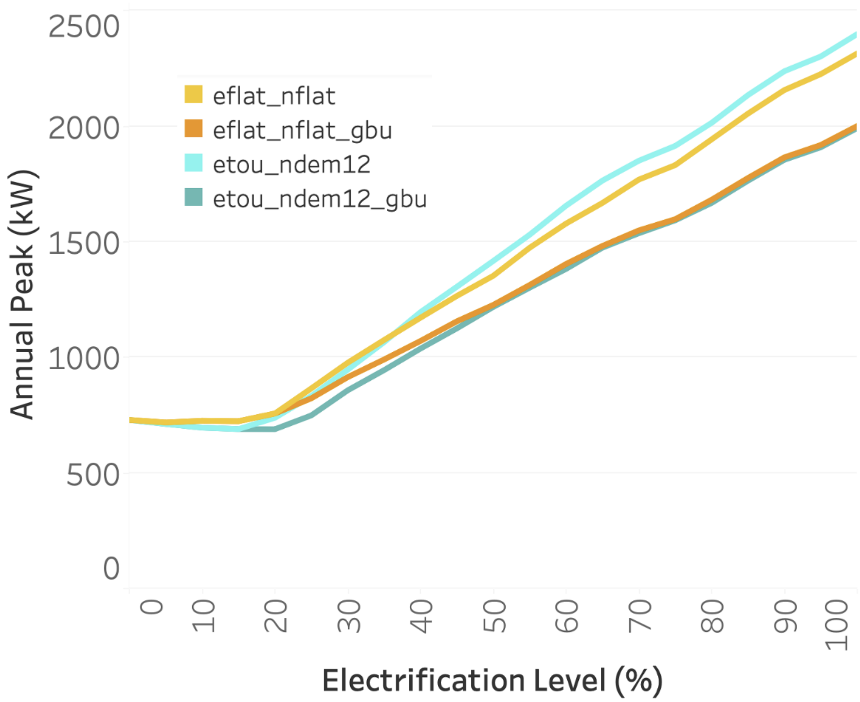


Figure 7.1: Annual aggregate peak demand in the Massachusetts case study for the *eflat_nflat* and *etou_ndem12* tariff scenarios with and without gas backup.

in Massachusetts case study with no backup (*eflat_nflat* and *etou_ndem12*) and with gas backup (*eflat_nflat_gbu* and *etou_ndem12_gbu*). We only allow the gas backup system to run at hours when the outdoor air temperature is below -15C (5F), which results in 2% of total annual heating demand met by gas. For the *etou_ndem12* tariff (where the effect is slightly more significant), adding gas backup reduces annual peak demand by 14% at 50% electrification and by 17% at 100% electrification. These reductions would likely be higher if not for a "rebound" phenomenon we observe during hours where the outdoor air temperature crosses the -15C threshold. During these hours, CCHP demand behaves in much the same way as correlated EV demand responding to a change in the energy charge; this could be mitigated by randomizing the temperature threshold.

Khorramfar et al. [72] find that when CCHP systems are sized for cooling load and paired with supplemental fossil heating, region-wide residential peak demand is halved compared to an electric resistance backup scenario. Notably, building envelope improvements also have a strong downward effect on peak heating loads, pointing to the importance of pairing weatherization with heat pump installations to avoid oversizing systems and achieve operating cost reductions.

Even with hybrid systems, in states like Massachusetts where natural gas is the dominant heating fuel, heating electrification implies a sharp reduction in utilization of the natural gas network. Under existing retail natural gas rates in many states, a large portion of network costs are recovered through a flat volumetric charge (similar to electricity). As more customers adopt CCHPs and use significantly less or no gas, the sunk costs of the gas network will not change. This reduction in gas consumption implies an increase in the perunit cost to recover the revenue requirement. As gas tariffs increase, there will be a stronger incentive to adopt heat pumps, reducing gas revenue further. This cycle – sometimes called a “utility death spiral” – poses a cost recovery challenge for gas distribution utilities and an affordability challenge for customers who continue to use gas for heating.

This problem is most acute if heating electrification proceeds “randomly” and gas utilities must maintain the entire existing network throughout the transition to electric heating. If instead regulators and utilities plan to decommission parts of the distribution gas network (e.g., entire neighborhoods), it is possible to achieve operating cost savings and avoid the need for network reinforcements to replace old and/or leak-prone pipes; Lechowicz et al. [163] demonstrate that a centrally-planned, "network-aware" transition scenario achieves 55% higher carbon reductions than an unmanaged transition under the same budget. Even with hybrid heating, it may be more cost-effective to rely on other forms of backup heat (e.g., trucked propane or fuel oil with on-site storage tanks). In Walsh and Bloomberg [164], the authors calculate that a non-pipeline hybrid system achieves a lower combined revenue requirement (inclusive of the electricity and gas networks) compared to a hybrid system using the existing gas network. Yet today in many states gas utilities have accelerated mains replacement rates for safety purposes [165], which will create more stranded costs down the road if there is high CCHP penetration.

In Massachusetts, this challenge is particularly relevant after a recent regulatory order (DPU 20-80-B) that disallows cost recovery for gas infrastructure without proof that non-gas alternatives were considered. This calls for regulatory innovation to protect households that have not yet electrified. While a detailed study of gas tariff design is outside the scope of this thesis, we can envision at least two potential solutions:

- A new rate designed specifically for heat pump customers who remain connected to the gas network for supplemental heating. This rate could shift a portion of network cost recovery to a fixed charge. In this case, regulators should be careful not to set the fixed charge too high, or else it will create an incentive to disconnect from the gas network entirely (leading to higher CCHP-driven winter peaks).

- A transfer payment from electricity to gas utilities that reflects a portion of expected future revenue from heating electrification. This may be easier to implement in areas where the same parent company provides both gas and electricity.

If backup fossil heating is either not allowed or not cost-effective, energy storage (either installed behind the meter or at the distribution substation) can help mitigate CCHP-driven local and regional peaks. We did not model the use of energy storage for this purpose so cannot comment on how the costs would compare to the costs of network expansion. While it is still early in the CCHP adoption curve in Massachusetts, we believe it is important to consider how to protect vulnerable users of both the gas and electricity networks well before the "utility death spiral" problem arises.

7.2.5 Balancing Stakeholder Interests for Efficiency and Solar

Energy efficiency and residential solar advocates have historically opposed tariff reforms that reduce the volumetric component of the bill (see, e.g., [152], [151]). While efficiency and solar deployment are both important components of economy-wide decarbonization, we don't believe they should take precedence over core rate design principles (notably cost-reflectiveness) or achieving beneficial electrification.

In many US states, residential solar customers are compensated under the net metering framework, whereby customers are charged for their net consumption (total consumed minus total exported) each bill period. When network costs are recovered volumetrically, consumers can avoid paying for the network despite continuing to rely on it during hours when their solar arrays are not generating. If distribution costs were recovered instead in part by a capacity or fixed charge and net metering continued, solar customers would not receive as much value. Yet there is no rule that solar compensation must be tied to the retail electricity rate. Rather, solar customers could be compensated for exported energy via a separate tariff. If supporting residential solar is a policy priority for states, the solar export tariff could be set to compensate at a higher value than the true avoided cost of the generated electricity.

Statewide efficiency programs typically target reductions in kWh energy consumption to alleviate energy burdens and reduce emissions. Yet as electricity generation becomes cleaner, kWh reduction will become a less effective proxy for carbon reduction. In 2020, Sacramento Municipal Utility District (SMUD), a municipal utility, became the fist utility to change their efficiency metric from kWh reduction to "avoided carbon." This reflects the fact that the most cost-effective way to reduce carbon emissions may actually require *increasing* electricity consumption (i.e., through electrification). Furthermore, several studies (e.g., [166], [167]) demonstrate that upfront rebates, federal appliance standards, and building codes may have a larger effect than the volumetric electricity rate on the uptake of energy efficient appliances.

7.3 Limitations of Methodology

In this section, we outline six key limitations in our approach.

First, we do not calibrate the levels of the network charges to actual forward-looking network costs. Rather, the tariff level is calculated using the total revenue requirement (including sunk costs). Our case study focuses on the incentives driven by tariff structures; under our assumption of rational price responsiveness, the absolute magnitude of each tariff does not impact customers' load shapes. Yet absolute magnitudes will affect distributional impacts and incentives to electrify. Furthermore, we use a simplified network model where investments grow linearly with annual peak demand. In reality, network investments would likely occur in a lumpy manner. However, a linear curve roughly approximates a utility's *average* upgrade costs over many distribution feeders [168].

Second, we treat energy prices as exogenous and do not recalibrate the timing of tariff windows (e.g., on-peak and off-peak) as load evolves. For the former limitation, energy TOU rates are typically a proxy for wholesale prices in the day-ahead or real-time markets (in ISO territories). While direct impacts of residential electrification on the wholesale market are expected to be limited initially, at high levels of adoption it becomes important to consider how the correlated response of flexible loads like EVs and CCHPs would impact wholesale electricity prices and thus affect TOU energy rates. We will investigate this topic in future work. For the latter limitation, while utilities sometimes make small changes to the start and end times of a peak period, TOU windows are remarkably "sticky." Part of the reason is that tariffs typically apply for all customers in a rate class despite considerable diversity in load profiles at different network nodes. For example, Green Mountain Power's residential TOU rate (Rate 11) has used the same on-peak window (12:00 PM – 9:00 PM on weekdays) for 9 years despite a marked shift in region-wide wholesale price patterns in that span (i.e., low mid-day prices from solar PV). However, we recognize that if rebound consumption due to EVs and CCHPs were to become the dominant driver of peak demand in an entire distribution territory, it is likely that the utility would amend the tariff to change the timing of the off-peak period. In any case, flexible loads would continue to react to relative price differences, so the risk of a correlated response would persist even if energy prices and tariff window setting were endogenous to the model.

Third, we assume all EV charging occurs at home with Level 2 chargers, even though one would expect to see a mix of charger types and locations in the future. According to a survey by Dunckley [169], 80% of charging occurs at home, with the remaining 20% at workplace and public stations. Our case study therefore represents a sort of worst-case scenario; non-residential charging would likely help reduce coincident peak demand in the evening by shifting charging activity to daytime hours, as shown by Needell et al. [77]. Furthermore, in urban areas or places with a high proportion of rental properties, it is unlikely that all residents would be able to install dedicated charging stations at home. Our case studies consider suburban residential feeders where homes have off-street parking and sufficient electric panel capacity to install a Level 2 EV charger. An important extension of our research is examining residential charging in urban settings where alternative charging methods exist. In addition, the implications of charging of delivery trucks and other fleets deserves study.

Fourth, we assume that non-EV and non-CCHP load do not respond to price. EVs and CCHPs represent a major source of load; for the Massachusetts case study, at 50% adoption EVs and CCHPs account for 39% of annual feeder-wide consumption. However, we would expect actual consumers to shift other loads (e.g., dishwashers and washing machines) to reduce costs, enabled by automation capabilities. This would mitigate peak demand growth and allow non-electrified households to reduce their network costs, improving distributional outcomes. However, we believe it is useful to consider the purely price-unresponsive case, as it isolates the distributional impacts of electrification under each tariff scenario and adheres to the perception among some consumer protection advocates that vulnerable households do not have the flexibilities in their daily schedules to respond to prices.[6] This is the same reason we chose to apply the alternative tariffs to the entire population rather than only electrified households given the trend towards default opt-out tariffs that achieve high participation rates.

Fifth, we associate only a single EV with each house. It is likely that some multi-vehicle households will purchase a second EV before all households have their first. We will address this possibility in future work, although we expect that capacity-based tariffs will perform similarly given that each home's demand or subscription cost is based on its aggregate

[6] Faruqui and Sergici challenged this perception in a survey of 15 TOU pilot programs, which found that low-income households responded at the same or higher rates compared to medium- and high-income households [66]. When subjected to time-varying rates, low-income customers reduced their peak demand by 17% during critical peak periods; this value more than doubled when customers were given enabling technology like smart thermostats.

demand.

Sixth, our analysis focuses specifically on EV and CCHP adoption. We did not consider the potential impact of other distributed energy resources, like solar and battery storage, which may help mitigate peak demand growth but introduce a host of other complex trade-offs, especially for compensating exported solar generation.

This chapter provided a discussion of our results and their implications for designing distribution network tariffs in practice. We also discussed limitations of our methodology, which highlight areas for future work. The following chapter offers concluding thoughts and policy recommendations.

Chapter 8

Conclusion and Policy Recommendations

Rapid electrification, through the adoption of electric vehicles and cold climate heat pumps, is required to achieve state and federal decarbonization targets. While recent federal legislation and state rebate programs reduce consumers' upfront purchase costs for EVs and CCHPs, there has been comparatively little effort to address operating costs, an important component in the total cost of ownership.

This thesis asks whether distribution network tariff reform can reduce the direct costs of electrification while protecting non-electrified households from higher bills resulting from new network investments. The central question was formulated in response to two prevailing trends: 1) Electric utilities are projecting steeply rising distribution network costs (which will be shared among all grid users) to accommodate expected load growth due to electrification; 2) Flat volumetric tariffs, which are nearly ubiquitious today in the US, result in high operating costs for CCHPs and EVs, a headwind to adoption, particularly for CCHPs.

Recent initiatives to reform network tariffs in the US do not adequately balance stakeholder interests and may create unintended negative effects. For example, some states (e.g., Missouri, Colorado, and Michigan) have implemented default TOU rates that collect both network and energy costs via a single charge. While these initiatives better reflect the underlying cost of electricity consumption and are a step in the right direction, they tend to focus on reflecting bulk system costs and ignore distribution system constraints. Without a per-kW capacity charge, these tariffs are prone to correlated responses from automated EV and CCHP consumption, which may yield higher network investments than under the status quo. California has proposed introducing an income-based fixed charge to shift recovery of sunk network costs away from the volumetric charge in an explicit attempt to improve the economics of electrification. While this approach adheres partially to the "efficient ideal" tariff design, it has faced intense backlash, offers no opportunity for customers to manage a large portion of their bill, and on its own fails to deter future network investments.

Much of the existing research on network tariff reform either focuses on cost changes at a single snapshot (imposing a condition of revenue neutrality) or ignores the potential for network investment. Among studies that address how to mitigate the impacts of electrification on distribution grids, many consider only direct load control. While load control will likely play an important role in the future, it would be a missed opportunity to ignore how tariff design, which can be deployed relatively quickly, can address the dual challenges of rapid decarbonization and energy affordability.

In contrast to prior work, this thesis considers the impact of tariff design on network investment in the long term, how rates affect incentives for customers to electrify, and the distributional impacts on households that have not yet purchased EVs and CCHP systems. We also consider network and energy tariffs that are designed independently, which is unique among a small body of similar research (see Table 3.1). We conducted two realistic case studies to test distribution network tariff performance in the face of electrification in two distinct geographies. Households react to tariff prices independently without any coordination among households or centralized control. We evaluated network tariff designs using three key metrics: annual peak demand, levelized electricity costs for EV and CCHP consumption, and change in network costs for non-electrified households.

We found that in mild climates where heating electrification is already prevalent, correlated EV charging causes new local network peaks as early as 25% adoption, a threshold we may have already crossed in some neighborhoods. In cold climates, CCHP consumption during extremely cold hours is the dominant source of peak demand growth, triggering network investments as early as 20% adoption. Our results indicate a tradeoff between reducing costs for electrified households and containing cost impacts for non-electrified households. We found that per-kWh distribution network tariffs, which several states have adopted as the default, lead to high electrification costs and lack a price signal to limit aggregated demand peaks, leading to high network investments. While fixed network charges reduce the cost of electrification, they shift costs from EV and CCHP households to non-electrified households and again lack a mechanism to mitigate peak demand. We find that per-kW capacity tariffs, which incentivize households to limit their maximum demand, are effective at reducing EV-driven peaks and operating costs for both CCHPs and EVs. When paired with a flat per-kWh charge to collect a portion of the network revenue requirement, per-kW tariffs can deliver savings for all grid users. Among capacity tariffs, demand charges perform well but may be difficult to implement. In light of these findings, we believe a subscription charge is a pragmatic compromise that performs relatively well on all dimensions.

Our results suggest that there is an opportunity, through distribution network tariff reform, to improve the economics of electrification while lowering energy burdens for households that have not yet electrified: a true win-win. We believe this outcome – beneficial electrification – should be the goal of any tariff reform effort in order to simultaneously address the urgent challenges of decarbonization and affordability. We hope this finding counteracts the narrative that a shift away from flat volumetric tariffs will necessarily harm vulnerable grid users who cannot shift the timing of electricity consumption. When viewed in the short term, any rate reform will create winners and losers because the same revenue requirement must be recovered. However, when we consider the long-term impacts, well-designed rates can reduce the need for network investment and accelerate electrification, delivering benefits for both electrified and non-electrified households. We note that the extent to which this beneficial electrification can occur is highly sensitive to the cost of network upgrades in each utility's service territory.

Finally, our results also indicate the limitations of even relatively granular distribution network tariffs coupled with TOU energy charges. We observe EV-driven rebound peaks (in response to a drop in the per-kWh price) even under demand and subscription charges. And when considering the concurrent electrification of home heating and transportation, we see a steep rise in aggregate peak demand under all tariffs. If we relax some of our tariff design principles (i.e., simplicity, non-discrimination, and existing widespread implementation), there are several alternatives to the distribution network tariffs tested in our case study. These include randomized TOU windows, daily capacity charges, curtailable contracts [170], auctions for network capacity [171], and dynamic price setting based on equilibria estimations [172]. Yet moving from the flat volumetric tariffs ubiquitous today in the US to these advanced and untested approaches would likely face significant resistance from utilities and regulators. In the near term, simple distribution network tariff designs like those implemented in Europe can be effective at limiting peak demand growth. They also offer a bridge to the complementary measures, including direct load control, which will become necessary as we reach higher levels of electrification and more volatile wholesale prices.

One of the key insights we hope to impart to regulators is that the prevailing heuristics for tariff design in the US are poorly suited for a world with highly automated demand from EVs and CCHPs. Rate design experts generally agree that a peak-to-off-peak differential of at least 2:1 is needed motivate customers to enroll in opt-in TOU rates and respond manually to price signals [34]. But when load shifting is tantamount to configuring an automated schedule in a mobile app one time, *any* price signal (even a modest one) may be sufficient, especially for opt-out whole-home rates. Without the constraint of a high daily peak/off-peak differential, regulators will have more freedom to allocate costs between different types of charges and set tariff prices in a way that improves electrification economics and protects vulnerable customers.

In summary, we recommend that PUCs separate the design of distribution network tariffs from energy tariffs and introduce a per-kW subscription charge to collect a portion of the distribution network revenue requirement. The subscription charge should be either mandatory or opt-out, and paired with a per-kWh charge to balance stakeholder interests. This combination has the potential to 1) mitigate the need for local network upgrades, especially at high electrification levels, 2) reduce costs for non-electrified households, and 3) provide low levelized costs for households adopting EVs and CCHP systems. Table 8.1 summarizes our key insights and recommendations to PUCs.

Table 8.1: Summary of key insights and policy recommendations

Key Insights

- Per-kWh TOU rates, which are gaining popularity among US regulators as replacements for flat volumetric tariffs, may perform worse than the status quo from the perspective of network investments. Under these rates, correlated EV- and CCHP-driven peaks could exceed historical peaks in the near future.
- Capacity-based distribution network tariffs are effective at mitigating these "rebound" peaks while reducing levelized electrification costs and protecting non-participating customers from high bills.
- While rate reform necessarily creates winners and losers in the short term, in the long term all grid users can benefit due to the rate-reducing potential of electrification. The extent to which this "beneficial electrification" can occur depends both on the tariff design and the long-run marginal cost of upgrading the network.
- Different service territories call for different tariff solutions. Historically, electricity cost has not not been a barrier to EV adoption. In contrast, CCHP adoption depends strongly on electricity cost. For CCHPs, in areas with high volumetric rates and gas heating, reducing the cost of operation is essential to accelerate adoption, which can apply downward rate pressure.
- While flat energy tariffs perform well from a network investment perspective by taking advantage of demand heterogeneity, there are considerations at the generation level that call for time-varying energy tariffs, which can capture both the relative differences and absolute magnitude of hourly wholesale electricity prices [153].
- EVs and CCHP have fundamentally different flexibility characteristics than other loads because of automation; a small price differential may be sufficient to incentivize load shifting.
- While in the near term, policies that mandate the removal of legacy heating systems in order to claim CCHP rebates may be effective at reducing emissions, in the long term these policies will exacerbate peak demand growth. Backup non-electric heating during the coldest handful of hours of the year can reduce network investment at only a small emissions penalty.

Policy Recommendations

- State PUCs should initiate distribution network tariff reform proceedings for each IOU in their jurisdiction to 1) separate energy tariffs from network tariffs and 2) design distribution network tariffs that include a per-kW subscription component and a per-kWh component. Both can be done under the existing cost of service regulatory framework without new legislation.
- In determining how to allocate network costs among charge types (i.e., subscription charge vs per-kWh charge), regulators should consider both incremental network investment costs and the gap between the electricity price and fuel price in each utility's service territory. In areas with low electricity prices or where EV adoption will dominate electrification-related growth, regulators should assign a higher priority to mitigating the impacts of correlated demand (along with other rate design objectives) and a lower priority to reducing the levelized cost of EV- or CCHP-related consumption.
- PUCs should start convening stakeholders to discuss the future of cost recovery for natural gas distribution networks as customers electrify their heating.

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